Strategies and incentives for integration of renewable generation using distributed energy resources

A case study based on the University of California, San Diego

A California Solar Initiative (CSI) Research, Development, Demonstration, and Deployment Program Grant

Task 6 – 8 Interim Report

July 17, 2013

viridityenergy

Energy+Environmental Economics

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Abstract

This study analyzes dispatch strategies and incentives for integrating high penetration photovoltaic (PV) systems and intermittent renewables using distributed energy resources (DER). This analysis provides novel contributions to existing research by: 1) documenting the potential to engage existing DER for renewable integration with limited additional capital expenditure, 2) modeling the dispatch, costs and benefits of microgrid operation for both customer and utility grid benefits, 3) integrating and optimizing both electric and thermal resources for renewable integration benefits and 4) comparing the costs and benefits of multiple strategies over a full year with validated historical data.

Our host site is the University of California, San Diego (UCSD) microgrid, which has a rich DER base that includes a 2.8 MW fuel cell powered by directed biogas, 30 MW of onsite generation, steam and electric chillers, thermal storage and roughly 1.5 MW of onsite solar PV. We develop and evaluate three strategies for integrating renewable generation: *peak load shifting, PV firming, and grid support*. The strategies are analyzed with an hourly dispatch optimization model of the UCSD microgrid and one year of data. Each strategy is assessed in terms of campus and grid energy impacts, and cost effectiveness to UCSD, California ratepayers, utilities, and the California ISO (CA ISO).

We find that UCSD DER dispatch strategies are technically feasible and can be cost-effective, but current tariff designs inhibit their performance, and net cost-savings are small relative to total campus resource costs. For each renewables integration strategy, we model and evaluate the cost-effectiveness of alternative incentive, tariff and resource dispatch cases. Our findings suggest alternative incentive mechanisms and engagement strategies beyond direct load participation and dynamic pricing strategies currently under consideration are needed. These strategies are relevant for DER resources across campuses and similar commercial and industrial loads across the state.

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Glossary

AS	Ancillary services : set of services procured by the balancing entity for balancing and power quality maintenance purposes
All-hours demand charge	The demand charge in SDG&E's tariff that is assessed on the monthly peak demand if it occurs outside of the on-peak time-of-use period.
CEC	California Energy Commission
CUP	central utilities plant
DA	Day-Ahead
DG	distributed generation
DER	distributed energy resources at a customer site (e.g., generation, efficiency, demand response, storage)
EMCS/ EMS	energy management control system/ energy management system
GHG	greenhouse gases
Load following	process of eliminating supply and demand deviations within the hour that occur on a ~ 5-20 minute timescale

Ramp	requirement to increase or decrease generation to meet sustained changes in demand; measured in MW/minute; early morning and late evening ramps are typical
RE	renewable energy
Regulation	ancillary service that is procured by the balancing authority to balance all deviations continuously; provide load following and frequency response
RESCO	renewable energy secure communities
RT	Real-Time
Setpoint	refers to a control system input or goal (e.g., temperature setpoint of an HVAC system)
Spinning reserves	on-line reserve capacity that is synchronized to the grid system and ready to meet electric demand within 10 min of a dispatch instruction; needed to maintain system frequency stability during emergency operating conditions and unforeseen load swings
Non-spinning reserve	off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction by the ISO, and that is capable of maintaining that output for at least two hours. Non-Spinning Reserve is needed to maintain

	system frequency stability during emergency conditions
PLS	peak load shifting. PLS is frequently used to refer permanent load shifting, which UCSD resources are also capable of providing.
TES	thermal energy storage
TOU	Time-of-Use
TRC	total resource cost

1 Executive summary

This study proposes and analyzes new business models for improving the economics and incentives for integrating high penetration photovoltaic (PV) systems and intermittent renewables using distributed energy resources (DER). We propose *peak load shifting, solar PV firming, and grid support* strategies for integrating renewables and simulate each strategy using one year of data from the University of California, San Diego (UCSD) microgrid, which has a rich DER resource base with onsite generation, thermal storage, and 1.5 MW of onsite solar. This work builds on prior CSI and California Energy Commission (CEC) Renewable Energy Secure Communities (RESCO) grants to UCSD and Viridity. This analysis provides novel contributions to existing research by:

1. Documenting the potential to engage existing DER for renewable integration with limited additional capital expenditure.
2. Modeling the dispatch, costs and benefits of microgrid operation for both customer and utility grid benefits.
3. Integrating and optimizing both electric and thermal resources for renewable integration benefits.
4. Comparing the costs and benefits of multiple strategies over a full year with validated historical data.

1.1 Policy context

California has significant clean energy goals. The Global Warming Solutions Act (AB 32) requires greenhouse gas (GHG) emissions to be reduced to 1990 levels by 2020, which led to the legislated 33% (by 2020) Renewable Portfolio Standard. The Million Solar Roofs initiative, net energy metering and zero net-energy goals for new construction encourage the adoption of PV at higher penetration levels. Numerous studies discuss potential challenges of integrating high penetrations of PV generation, ranging from utility concerns regarding backflow in distribution systems to real-time supply-demand balancing challenges for the CAISO, which must also address long-term resource planning questions.

California's *Energy Action Plan* places distributed energy resources (DER), specifically energy efficiency, demand response and distributed generation at the top of the 'loading' order and numerous policies promote their adoption. FERC orders 745 and 755 promote the direct participation of loads and DERs in energy and ancillary service (AS) markets. This project is a timely and important case study to explore how DERs can integrate high penetration renewables cost-effectively, and is relevant given the vast existing DER resource in California and declining costs of DER due to innovation.

1.2 Objectives

The broad goal of this work is to explore how DER can cost effectively integrate high penetrations of solar PV. More specifically, the project objectives include:

- Technical feasibility
    - Characterize campus resources
    - Develop dispatch and optimization strategies for DER
- Economic feasibility
    - Test strategies in resource optimization model
    - Perform cost-benefit analysis
- Business case
    - Develop tariffs, incentives and business models
    - Disseminate results

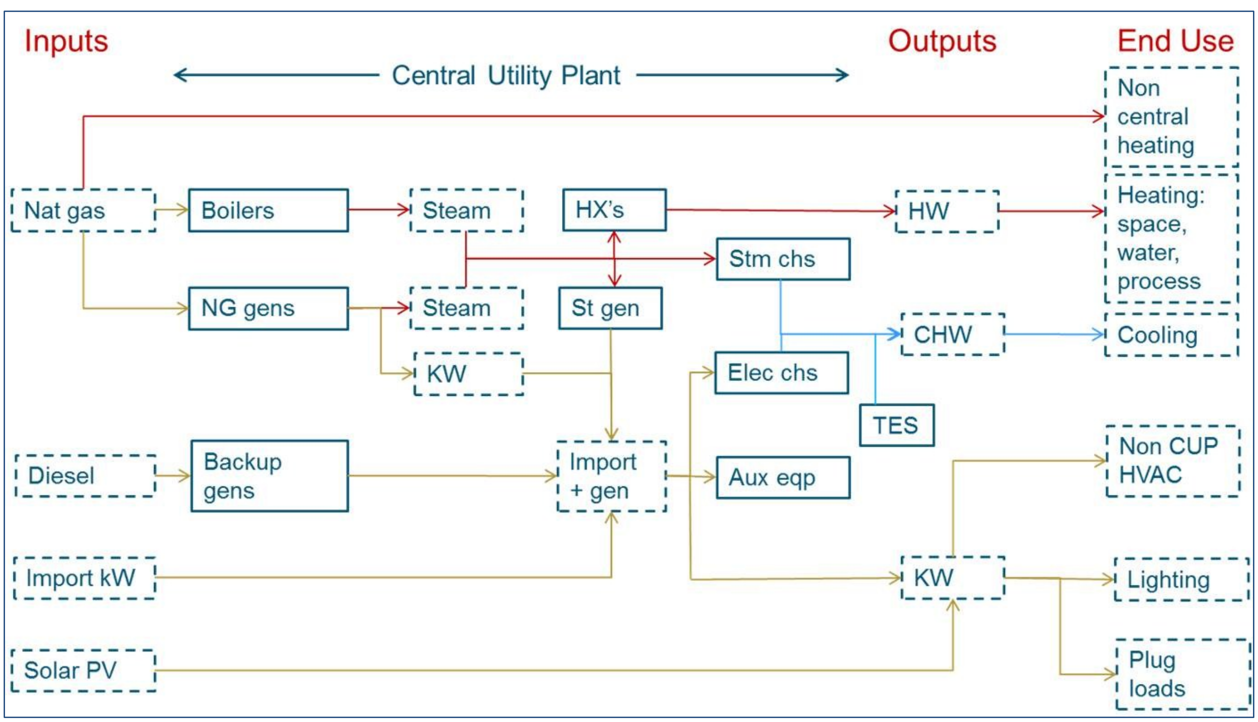
With these objectives, this projects offers useful suggestions to UCSD and policy makers on how to overcome gaps and barriers to promote the use of DER for renewables integration.

1.3 Approach

1.3.1 Characterize campus resources

We characterize UCSD resources, focusing on the UCSD Central Utility Plant (CUP). Figure ES-1 describes the energy flows across UCSD from the primary energy inputs (electricity, natural gas, diesel, solar energy) by end-use at the building level. The outputs of the CUP are electricity, chilled water and hot water. The CUP has two 13.3 MW natural gas generators that can meet ~80-90% of UCSD's electrical needs. Energy is recovered from the natural gas generators exhaust to produce hot water, chilled water (through steam chillers), and/or electricity (through a 3 MW steam generator). The CUP contains steam and electric chillers and boilers, which generate steam for producing hot water and potentially for the steam chillers. A 3.8 million gallon thermal energy storage (TES) tank provides chilled water during peak periods. Some buildings have individual HVAC systems and are not served by the CUP. Finally, UCSD has ~1.5 MW of onsite behind-the-meter solar PV that supplies non-CUP HVAC, lighting and plug loads...

Figure ES-1. Campus resources energy flow diagram



We use a year of interval data to baseline the CUP resources, understand campus electrical, hot water and chilled water needs, individual system efficiencies (e.g., heat rates of the generators), overall system efficiency and typical operations. We also obtain data on UCSD's actual solar generation and their forecasted solar generation. The resulting information is used in the modeling that follows in subsequent steps.

1.3.2 Renewables integration strategies

We develop three strategies of *peak load shifting, PV firming and grid support* to test DER's operational and economic viability of integrating renewables. We evaluate the *variable* energy impacts, costs and benefits for each strategy against a base case defined by UCSD microgrid's status quo.[1] For each strategy, we determine whether the dispatch strategy is technically feasible and cost-effective from two perspectives: (a) total resource costs and (b) UCSD as a utility customer. If the answer is 'yes' to the first perspective, but 'no' to the second, we explore the tariff and regulatory changes required to motivate greater participation by UCSD and similarly situated large commercial and industrial (C&I) customers.

The three strategies considered herein have useful features described below:

Peak load shifting. With greater renewables penetration, PLS will become increasingly important to manage later peaks with increasing solar generation and to use abundant nighttime wind generation that is now at times curtailed to maintain the state's real-time system resource-load balance. PLS is clearly technically and economically feasible, as it is already done by UCSD. What's less clear is how current tariffs could be redesigned to motivate large C&I customers to provide additional load shifting or invest in new PLS infrastructure. Our case in point is the current all-hours demand charge of the SDG&E AL-TOU tariff, which applies outside of the on-peak TOU period and can increase a

[1] As this study focuses on the use of existing DER, fixed costs are not considered.**

large C&I customer's monthly bill if PLS increases peak demand in the off-peak TOU period above the peak demand in the on-peak TOU period.

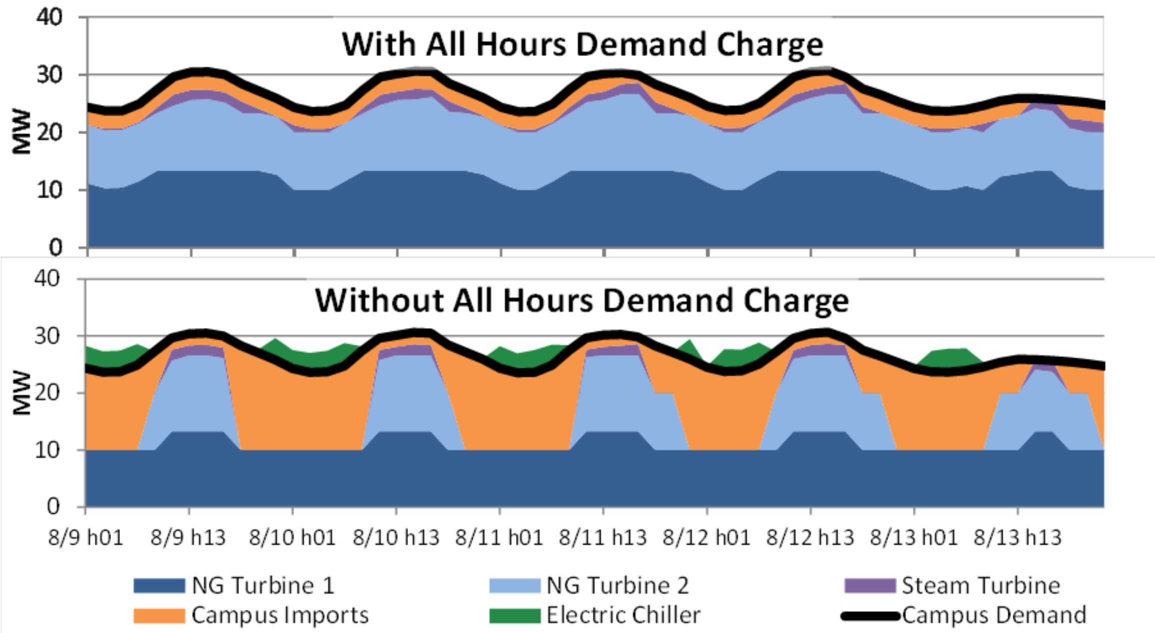
PV firming. This strategy seeks to manage the difference between actual and forecasted solar generation (i.e., forecast error) at UCSD. We model the operational feasibility of reserving a quantity of flexible capacity from UCSD resources to 'firm' campus PV generation under increasing levels of PV penetration. As there is currently no explicit cost or penalty to UCSD for PV forecast error, we develop a hypothetical rate scheme (similar to the energy imbalance tariff used by a grid operator of a wholesale market) that penalizes UCSD for deviations from the day-ahead forecast. We then assess the customer and TRC cost-effectiveness of using UCSD or grid resources to firm PV generation.

Grid support. This strategy aims to use UCSD resources to provide balancing services to CAISO to aid integrate large scale renewables outside of the UCSD campus. We first model the flexible range of UCSD's natural gas generators (6.6 MW) to provide a fixed amount of regulation up and down each hour. We evaluate if additional campus resources can increase the amount of grid support within the context of the existing frequency regulation market. We compare UCSD's costs of providing regulation to determine whether the strategy is cost-effective from both the TRC and UCSD view.

1.3.3 UCSD Dispatch Optimization Tool

E3 used *Analytica* to develop the UCSD Campus Dispatch Optimization Tool to quantify the net benefits of each strategy. This tool performs hourly, rather than sub-hourly, dispatch optimization to implement scenario analysis over hourly, monthly and annual time scales. By incorporating the physical relationships of the CUP resources described in Figure ES-1, it minimizes UCSD's costs by dispatching resources to meet UCSD's electrical and thermal needs, while obeying physical constraints such as capacity and minimum run times. An example output of the tool is shown in Figure ES-2 for scenarios that include and exclude an all-hours demand charge from UCSD's tariff.

Figure ES-2 Illustrative example of modeled optimal dispatch with and without the all-hours demand charge.



Removing the all-hours demand charge provides greater freedom to the campus to take advantage of low cost electric imports during off-peak hours. The chart shows that without the all-hours demand charge, the second natural gas turbine is turned off at night and electric chillers, rather than steam chillers, are used to charge the TES tank.

1.4 Key results and discussion

We find that all three strategies are technically feasible for UCSD. Using cost information for each strategy's impact on the state and UCSD, determine the strategy is cost-effective from the TRC perspective and UCSD's perspective.[2] Our results are summarized in Table ES-1 and detailed in Section 5. While the evaluation is done with a full year historical data, we provide the results for a single month of representative results (August, 2011) for easy presentation and comparison.

[2] UCSD energy costs are a mix of wholesale costs and retail rates, which reflect, respectively, the TRC and customer (PCT) perspectives. Because retail rates are (almost) always higher than wholesale (TRC) costs, we reasonably assume that the actual TRC cost will be less than or equal to the UCSD cost for purposes of evaluating cost-effectiveness from a California perspective.

Our analysis shows that PLS is technically and economically feasible, but that the all-hours demand charge is an impediment to fully utilizing the flexibility of existing campus resources. Restructuring this demand charge and recovering fixed distribution costs elsewhere could generate additional peak reductions up to 1 MW and reduce UCSD costs by 6%.

PV firming is also operationally feasible. However, there currently is no incentive for UCSD to firm its own PV generation. Based on our hypothetical scheme that penalizes UCSD's forecast errors, PV firming with the natural gas and steam generators is consistently less expensive than the natural gas generators alone. However, it may be less costly for UCSD to use of its own grid resources to manage its forecast error. But this finding does not fully capture the cost of grid resource cost at the distribution level, where the most significant challenges to distributed PV exist. Further study is needed to assess integration costs at the distribution level.

Table ES-1 Cost benefit model results for the three sets of strategies from August of 2011

Peak Load Shifting	**MW of On-Peak Reduction**	**Change in Cost**
No all-hours and higher on-peak demand charge	1.05	-6.5%
Shorter summer on-peak demand period	0.20	-0.02%
PV Firming	**\$/MWh of PV Forecast Error**	**Change in Cost**
Two-part tariff with error penalty	\$44.43	0.35%
Natural gas generator support	\$64.86	0.68%
Natural gas and steam generator support	\$47.59	0.50%
Grid Support	**Average Total MW Bid per Hour**	**Change in Cost**
Natural gas generators, bid up & down together	1.9	-0.3%
Natural gas generators, bid up & down separately	5.1	-1.1%
All UCSD resources, bid up & down separately	6.2	-1.2%

Note: a negative change in cost indicates cost savings relative to the base case. In the case of PV Firming, there is no firming cost to the campus in the base case, so the change in cost is positive for all cases.

The final strategy, grid support, is also technically feasible. In providing frequency regulation, UCSD is participating directly in the wholesale AS market, earning sufficient revenues to reduce net costs. This shows that the strategy is cost-effective both from the TRC and customer perspective. Including additional resources/flexibility as potential regulation providers, however, may only reduce campus energy costs by a small percentage (~1 %).

1.5 Conclusions, recommendations, benefits to California

Using UCSD as a case study, our findings suggest that DER are technically capable of providing cost-effective integration services. These findings, however, also suggest that incentive and program design changes are needed to strengthen the business case for large C&I customers.

Peak load shifting. Restructuring the all-hours demand charge (which would require recovering demand related fixed costs elsewhere) could increase a large C&I customer's cost-effective peak-load reduction. In the case of UCSD, our estimated increase is about ~ 1 MW.

+ **PV firming.** PV firming by a large C&I with its own resources feasible but may be more costly than relying on the grid. Based on the case of UCSD, we find that there is a need for further research on the need to assess cost-effectiveness at the distribution level, where the impacts of high PV penetration are most pronounced.
+ **Grid support.** A large C&I customer may profitably offer grid support service. For the UCSD case, we find small energy cost savings. But the savings can increase with additional resources enlisted to provide independent up or down regulation bids.
+ **GHG emissions impacts.** The impacts of GHG emissions across renewables integration strategies vary and we do not find consistent GHG emissions reductions for our case study. However, our evaluation compares only the marginal GHG emissions for energy production. The additional benefits of using

DERs to enable higher penetrations of renewables and reduce GHG emissions of cycling fossil generation is not captured.

The above findings lead to the following recommendations to policy makers:

+ Restructure the all-hours demand charge for PLS customers to promote greater peak load shifting and increased off-peak load to absorb excess generation. Recover demand related distribution costs via alternative mechanisms that do not discourage beneficial peak load shifting.
+ Allow utilities to negotiate terms on an individual basis with large C&I customers to accommodate unique capabilities and appropriate, site specific baseline calculations.
+ Support development of an operationally robust dispatch model that accounts for uncertainty and assesses the benefits and risks from complex operational strategies. Also develop computationally efficient optimization approaches hourly or sub-hourly dispatch over daily, monthly and annual time steps with more powerful optimization engines.
+ Support an implementation study of DER integration strategies using UCSD as a pilot site. Modest additional effort would leverage this work and use UCSD as a case study produce a great deal of information on how modeled strategies translate to real world operation.

The insights from this study are relevant beyond UCSD. There is significant technical potential for using existing DER at C&I customers across California to provide renewables integration services. College campuses total 500 MW of load; industrial customers total over 2000 MW of load[3] and have many controllable end-use loads (pumps, fans, motors); there are ~ 8500 MW of combined and heat and power systems at ~ 1,200 sites in California[4]. Many of these customers have similar DER system types

[3] Itron 2007, Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond Task A4 . 1 Final Report : Scenario Analysis to Support Updates to the CPUC Savings Goals Main (2007), at 37.

[4] ICF International, 2012. Combined heat and power: Policy analysis and 2011-2013 market assessment. Report prepared for the California Energy Commission. Report CEC-200-2012-002

as UCSD and could potentially provide renewables integration services. Our analysis shows that a simple policy change —removing the all-hours demand charge can decrease load by ~ 1 MW at UCSD.

Finally, this project has generated insights, tools and strategies beyond renewables integration. In particular, similar analysis can be done for California colleges to reduce their overall energy consumption, costs and GHG emissions, which is highly relevant in an era of cost consciousness and university sustainability goals.

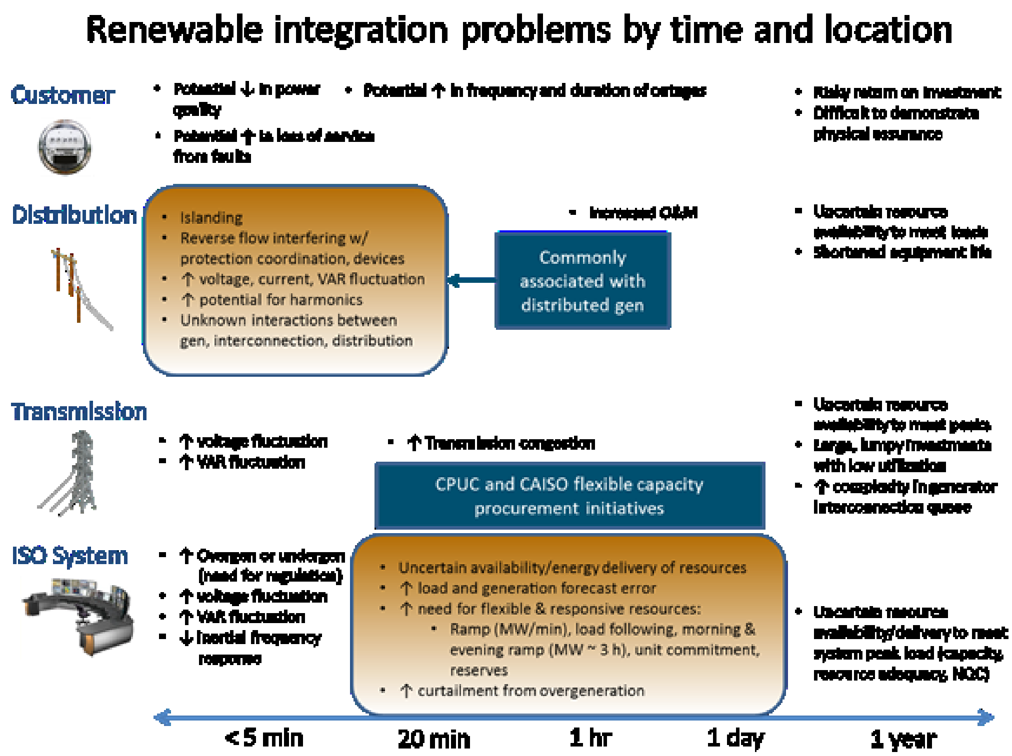
2 Introduction

This report presents our findings and recommendations for dispatch strategies and business models to encourage renewable integration with DER. The work is performed under Tasks 6-8 of the CPUC's California Solar Initiative (CSI) Grant Solicitation 2 awarded to Viridity Energy, Inc. (Viridity) and Energy and Environmental Economics, Inc. (E3) to study innovative models, rates and incentives to promote integration of high penetration PV with real-time management of customer sited distributed energy resources (DER).[5] Numerous policies promoting renewable and distributed generation in California motivate this work. The CSI has a target of 1940 MW of new solar capacity by 2016 in support of the State of California's Million Solar Roofs Program and the California Renewable Portfolio Standard (RPS) requires 33% penetration by 2020. Numerous studies highlight the potential challenges from high penetration of variable renewable generation.

Figure 1 illustrates the diverse nature of renewables integration challenges, from procuring sufficient flexible capacity years in advance to managing rapid variations in load and generation over minutes to seconds. Our work focuses primarily on how DER can address integration challenges at the 15 minute to 1 hour timescale, both at the distribution and system grid level.

[5] CSI Solicitation #2 was titled "Improved PV Production Technologies and Innovative Business Models".

Figure 1: Potential grid problems from increased renewables



The University of California, San Diego (UCSD) provided the host site for this project. The UCSD microgrid consists of a rich DER base that includes a 2.8 MW fuel cell powered with directed biogas, 30 MW of onsite natural gas generation, steam and electric chillers, a 3.8 million gallon thermal energy storage (TES) and roughly 1.5 MW of onsite solar PV, including two sites with PV integrated energy storage. UCSD owns and maintains a 69 kV transmission substation and four 12 kV distribution substations on campus, with multiple PMU synchrophasors installed by SDG&E. UCSD is also in the process of installing over 50 Level 2 & 3 electric vehicle charging stations.

The objectives of this work (Section 3) were to develop dispatch and optimization strategies using UCSD resources to support the integration of renewable and distributed generation. Our project approach (Section 4) was to characterize the campus resources in the UCSD Campus Optimization Tool developed by E3. We use these models to test the impacts and cost-effectiveness for three types of strategies: peak load shifting, PV firming, and grid support. The results (Section 5) show that cost-effective integration strategies are possible with DER's and identify specific tariff and market barriers encountered. We summarize our conclusions in Section 6 and recommendations in Section 7. The public benefits to California are presented in Section 8. Appendices provide detail on the historical data and modeling approaches used.

3 Project Objectives

The broad goal of this study is to explore how distributed energy resources (DER) can cost-effectively integrate high penetrations of solar PV. We develop innovative strategies to accomplish this goal and evaluate these strategies using the UCSD campus as a case study. The proposed strategies are designed to overcome current gaps and barriers in energy markets, utility programs and tariffs.

3.1 Develop dispatch and optimization strategies for DER

The first objective is to develop dispatch and optimization strategies for DER to reduce energy costs, integrate renewable generation and support reliable grid operation. DER currently provide services in the form of demand response, energy efficiency, load shifting that result in benefits to consumers, utilities and the grid. These resources could potentially be purposed towards supporting renewables integration more directly and should be studied for the following reasons:

+ A substantial quantity of DER currently exist in California and at the distribution system level where critical barriers to distributed renewables generation exist
+ DER can have environmental advantages in the form of reduced greenhouse gas (GHG) and criteria pollutant emissions, and water savings; this is reflected in DER being at the top of the CEC's loading order in the Integrating Energy Planning Report and CPUC's program objectives.
+ Costs of DER enabling and control technologies are rapidly declining

3.2 Test strategies in UCSD Campus Dispatch Optimization Tool

The second objective seeks to test the DER management strategies in the UCSD Campus Dispatch Optimization Tool. Once the models and optimization results are validated against campus operations and compared to the campus baseline performance, key inputs are varied from static data sources to simulate the different strategies to be tested.

3.3 Perform cost-benefit analysis

The third objective is to identify strategies that are cost-effective. Credible cost-benefit analysis is needed to evaluate trade-offs among alternative strategies and develop broad stakeholder and policy support for those that are the most effective.

California is investing billions of dollars towards clean energy generation. Technical strategies to integrate high penetration renewables exist; however, the key challenging is integrating these resources in a cost-effective, reliable and environmentally sound way. Alternative solutions include new infrastructure investments, new wholesale market products, modifying market rules and tariffs, and control strategies.

3.4 Develop tariffs, incentives and business models

This objective aims to develop the tariffs, incentives and business models that can encourage cost-effective implementation of renewables integration strategies. With increasing PV adoption, net energy metering has become more controversial and is challenged by utilities and ratepayer advocates. Tariffs and incentives that address multiple stakeholder needs and are cost-effective from across perspectives is essential for continued viability of DER. For each dispatch strategy proposed, we assess the potential for developing rates and incentives that can simultaneously motivate consumer adoption and provide net benefits to the utilities, ratepayers and society.

3.5 Disseminate results

This objective is to disseminate the results to the public, particularly to policy makers and large commercial and industrial customers that may adopt the findings.

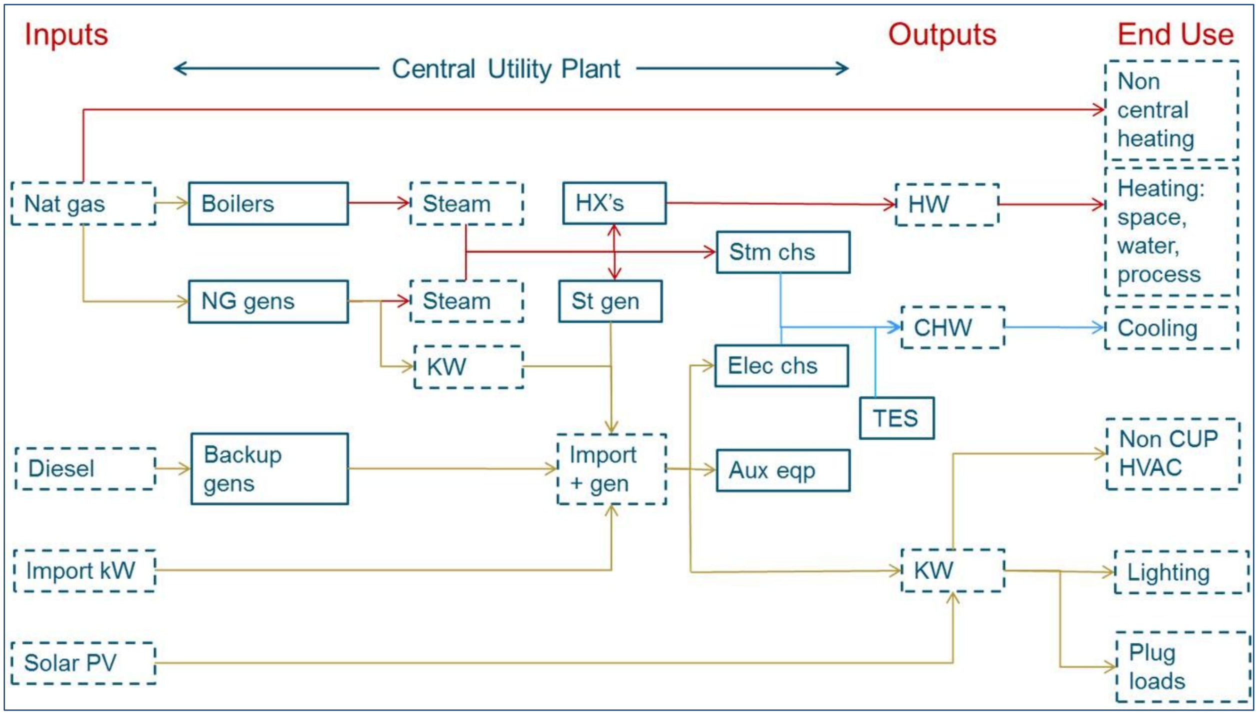
4 Project Approach

4.1 Characterize campus resources

The UCSD microgrid is a complex system that meets much of the campus's electrical and thermal needs. Figure 2 describes the energy flow from the primary energy inputs to end-use service.

At the heart of the central utility plant (CUP) are two natural gas generators ("NG gens") each with a 13.3 MW capacity. The generators typically operate at all times. Energy is recovered from the generators' exhaust to produce steam, which is used to produce hot water; generate additional electricity through a 3 MW steam turbine; or generate chilled water through steam driven chillers. The 'loading' order for utilizing the recovered energy is based on heuristics: in the summer, chilled water is generated, followed by hot water generation, followed by steam generator operation. In the winter, hot water is generated, followed by chilled water generation, followed by steam generator operation. The generators produce roughly 80% of the campus electrical needs on average and the remaining electrical needs are met through electrical imports.

Figure 2: Campus resources energy flow diagram



The CUP generates chilled water through a combination of the three steam-driven chillers (~ 10,000 tons of capacity) or five electric chillers (~ 7800 tons of capacity). The CUP has a 3.8 million gallon thermal energy storage (TES) tank that provides chilled water during peak periods; the TES tank pump allows the TES to provide ~ 3100 tons of chilled water. The TES tank is discharged with the purpose of avoiding electric chiller operation in peak periods. UCSD's hot water needs are met by utilizing recovered waste heat from the generators and by operating the boilers.

Some campus buildings have individual HVAC systems and are not served by the CUP. UCSD has roughly 1.5 MW of behind-the-meter solar PV; a 2.8 MW fuel cell and PV integrated energy storage which were installed after our analysis was conducted.

Minimizing campus energy costs is a complex process that involves optimizing the CUP generation for optimal use of recovered energy and operating the TES tank and electric chillers to minimize energy and demand charges. The presence of an all-hours demand charge complicates the CUP optimization process because turning on the electrical chillers and turning off the generators during off-peak periods risks moving the maximum demand, which determines the all-hours demand charge, to the off-peak period. Currently, UCSD uses heuristics to inform operation. We show in Section 5.1 that this method is reasonably effective, though a formal optimization tool could further enhance energy savings.

We obtain more than one year of interval data to characterize UCSD's electrical, hot water and chilled water demand; UCSD solar generation and forecasted generation; individual and overall efficiency of UCSD's 'combined heat and power' system which includes the natural gas generators and systems that utilize the recovered energy (i.e., steam chillers, hot water heat exchanger, steam generator); nominal capacities; and operating heuristics. We later use the electrical and thermal needs, individual system efficiencies and capacities and solar generation in the cost benefit modeling.

A companion report to this document, "*Task 5. Report on baseline performance for UCSD DER operation under current rates and incentives*" includes detailed results of the data collection and analysis effort and can be found at the CSI website.

4.2 Base case development

We apply the results of the baseline performance report to develop an appropriate 'base case' for each of the renewables integration strategies evaluated.[6] The baseline analysis is performed initially in Excel and subsequently in the UCSD Campus Dispatch Optimization Tool (Section 4.3). The analysis establishes that the E3 developed optimization tool models the operation of campus resources consistent with the historical dispatch performed by campus operators. Many of our strategies rely on operation of UCSD's flexible generation and thermal storage resources; we sought to

[6] *Task 5. Report on baseline performance for UCSD DER operation under current rates and incentives*" available at *calsolarresearch.org/Funded-Projects/second-solicitation-funded-projects.html.*

confirm that UCSD is motivated economically to operate these systems (particularly its campus generation resources). We also sought to understand the value proposition of moving beyond heuristics based operations to an optimization based approach.

The second set of analyses is performed in the more complex Analytica cost benefit optimization tool. We evaluate the same cases explored in Excel. The cost benefit model employs a two-step analysis approach to develop optimal dispatch results that minimize demand charges: the first step determines the optimal levels of all-hours and on-peak demand over a whole month while the second step determines a detailed hourly dispatch given those optimal levels of demand.

4.2.1 **Full electrical imports case**

This case illustrates the cost of operating the campus with the minimal set of DERs. The full imports case assumes that the campus relies solely on the grid for electrical energy and boilers for steam and hot water production. We model this case assuming both steam and electric chillers can be used to generate chilled water because the electric chiller capacity is insufficient to meet peak cooling demands during some hours (in this case, the steam chillers are fueled by boiler steam).

4.2.2 **Full imports with TES case**

This case is identical to the full imports case but adds UCSD's TES system. The optimization engine of the cost benefit model can choose to dispatch the TES to generate peak demand savings.

4.2.3 **Cogeneration case**

This case allows the operation of UCSD's natural gas and steam generators. The cogeneration case reflects all of UCSD's DER, except the TES system.

4.2.4 **Cogeneration with TES case**

The final case allows the dispatch of all of UCSD's resources and among the cases explored, most closely represents the systems at UCSD at the time of our analysis. The optimal solution of this case represents the theoretical minimum cost of operating all UCSD's resources. The base cases of other strategies are variations on this cogeneration with TES case.

4.3 Cost-benefit model implementation

E3 developed the UCSD Campus Dispatch Optimization Tool using the *Analytica* software platform. The modeling framework is based on the CUP energy flows shown in Figure 2 and uses a mixed integer linear program to develop dispatch schedules for the CUP systems to meet the campus electrical, hot water and chilled water demands in a manner that minimizes total operating costs, including demand charges. The cost benefit model uses historical hourly campus demands from June 2011 to May 2012 and historical natural gas and electricity prices across all cases. The model does not optimize any of the systems outside of the CUP, such as other HVAC systems, backup generators or auxiliary equipment. Focusing on one year of historical data, the model considers changes in variable operating costs only. The fixed cost of existing equipment is considered sunk, and no capital investment in new resources on campus is contemplated.

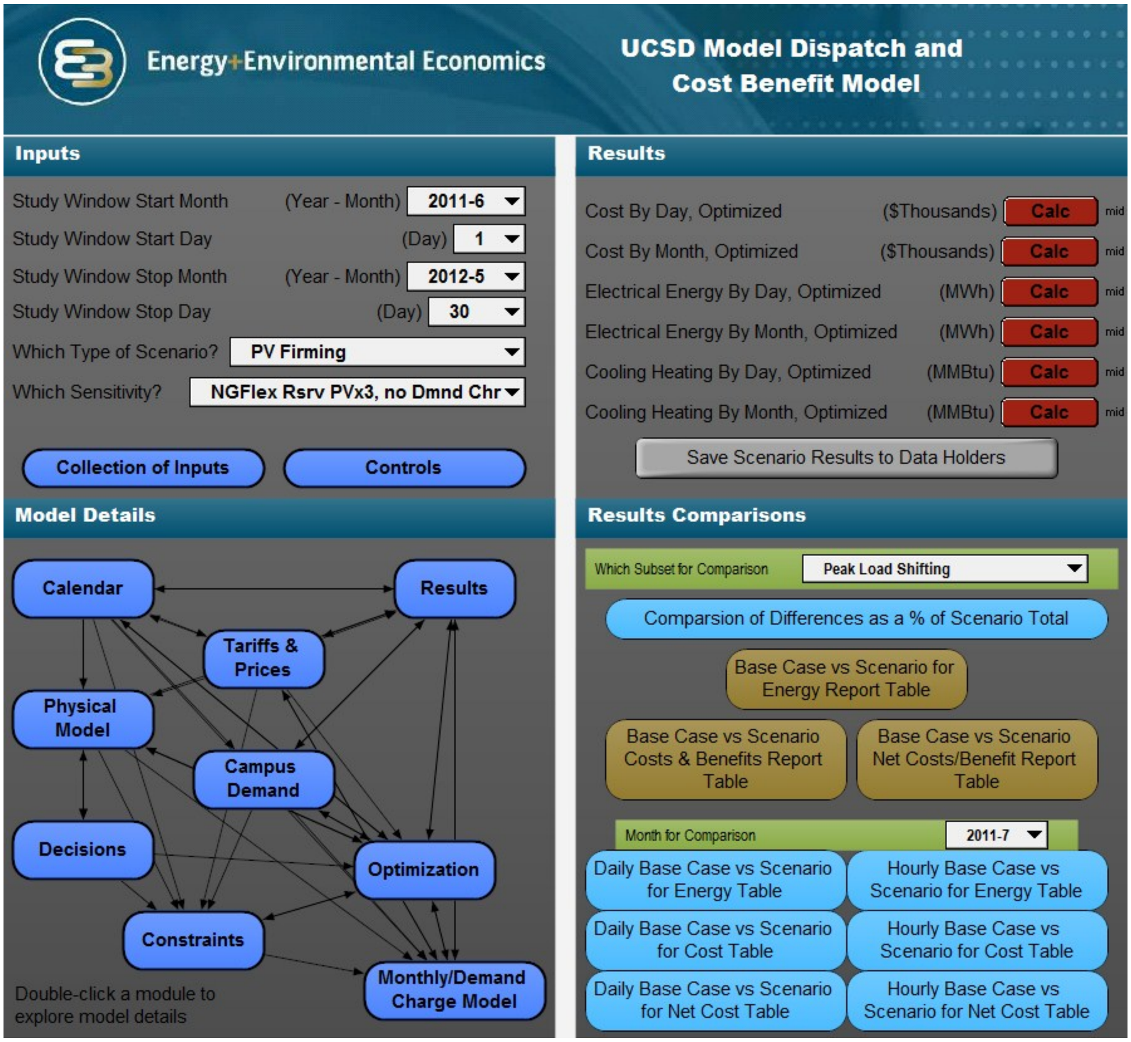
Our model incorporates operating constraints in the form of upper and lower operating capacities, startup costs, and minimum run times for CUP equipment. The optimization engine must determine schedules that meet UCSD's electrical and thermal requirements while satisfying these operating constraints. A key feature of the model is TES tank management: the model determines discharge and charge schedules subject to charge/discharge rates, such that monthly demand charge is minimized.

The model performs the optimization over two different time frames, minimizing for either daily total cost or monthly total cost. The monthly approach is important for capturing demand charges accurately, which requires knowledge of demand over the entire month. Because the optimization model has perfect foresight over the period being solved (for example, the electrical demand 12 hours away), using two different time frames allows for a balance between more or less forward looking results.

For the monthly minimization, due to computational limits, we reduce the temporal and resource resolution. Rather than developing hourly schedules, bi-hourly schedules are developed; chillers are aggregated and minimum run times are not imposed on these systems. Bi-hourly campus demands are generated from hourly data.

The daily minimization, which runs for consecutive days, requires constraints to be satisfied each hour of the day and passes the operating state of each resource (e.g. is a resource on, how many hours has it been running) and maximum demand level from one day to the next. The daily time frame affords greater time resolution at the expense of suboptimal results for the demand charge and TES tank management. The monthly time frame does not offer the same temporal granularity, but produces optimal solutions for demand charges that are assessed on the monthly peak load. These two approaches can be integrated by feeding month long optimization results into the daily optimization.

Figure 3: Screenshot of the cost benefit model



We make the following approximations to reduce solving time and to maintain the number of variables and constraints within the software limits:

- Chiller, generator and boiler efficiencies are represented as constant values, rather than a function of the output
- Steam production is assumed to be constant from the natural gas generators between minimum and maximum electrical output operating levels; this assumption is based on UCSD's operational experiences

- The boilers are represented as an aggregated single unit rather than as three independent units
- The TES must be fully recharged at the end of the period of total cost minimization
- For the month long model additional approximations are required:
    - A bi-hourly time step, with hourly campus needs and prices averaged over every two hours into a single time steps
    - Only gas turbine minimum run times are included
    - Individual chillers are aggregated into composite chillers, steam and electric, with weighted average efficiencies

4.4 Dispatch strategies

We develop several strategies to test the operational and economic viability of different rate and incentives that encourage distributed resources to provide additional customer and system benefits. Each strategy for dispatching campus resources is compared against a base case to derive the incremental costs and benefits of implementing the strategy on the UCSD campus. The strategies are divided into three categories: peak load shifting (PLS), PV firming and grid support. PLS strategies seek to reduce peak load and UCSD energy costs while simultaneously providing incremental utility or societal benefits. The PV firming strategies address the intermittency challenges from UCSD's onsite solar PV using either UCSD resources or relying on the grid. In the final category, grid support, UCSD participates directly in CAISO wholesale markets to provide ancillary services.

4.4.1 Overall approach to defining and evaluating strategies

All strategies share a common set of campus demands— electrical load (including the contribution of behind-the-meter solar generation), chilled water demand and hot water demand—which must be satisfied in the optimization. We start with the base case described in Section 4.2 and go on to establish distinct base cases for each of the three strategy categories analyzed. The three base cases share the common input data but they differ from one another as a result of differences in how each category of strategies are modeled.

We evaluate each strategy by its net cost, relative to its base case, defined as follows:

$$Net\ cost, strategy = [Total\ cost\ - revenue], strategy - [Total\ cost], base\ case$$

This change case less base case model allows us to isolate the impacts a strategy has on a common framework of assumptions. Using the net cost metric, we can compare outputs from different strategies with a shared base case to determine how changes inputs translate to costs or savings to the campus. Positive net costs indicate the strategy is not cost effective, relative to its base case; negative net costs indicate the strategy is cost-effective.

4.4.1.1 ***Presenting results***

We summarize the results for each strategy category in three ways.

+ First, we show an example week of resource dispatch, showing how the dispatch of campus resources changes with each successive case. This illustrates how the strategy impacts the dispatch of campus resources, and how changing constraints or available resources alters that dispatch.
+ Second, we show the change in net cost from the base case for each type of cost for the campus: electricity import costs, demand charges, natural gas costs, incremental revenues (if any) and the net impact of all four summed together.
+ Finally, we show the net cost impact for a summer and winter month.

The optimization for each case is performed over the entire one year period of analysis (June 2011 – July 2012). We present a subset of results for two reasons. First, it is far easier to effectively represent and highlight impacts over the weekly or monthly time frame than it is for a full year of hourly data.

Second, due to computational limitations, the model does not solve consistently for all the days and months of the year. In all cases, more that 93% of the days/hours solved in the optimization, giving a good representation of performance across the year and varying conditions. We chose a winter and a summer month that were directionally consistent with the results for most months of the year.

4.4.2 **Evaluation criteria**

We evaluate the net costs metric under a number of criteria. These criteria form the basis for assessing the strategies in our analysis in light of our research questions.

Does integrating additional resources in strategy dispatch decisions reduce costs or increase potential?

For each strategy, we evaluate several cases in a step-wise fashion. In some cases, we remove constraints or add additional campus resources to the portfolio included in the dispatch strategy. Across all three categories, we evaluate the benefits of including additional flexibility or resources in the mix. For example, we evaluate the extent to which adding the steam generator and electric chillers in the optimization for grid support increases the quantity provides and/or reduces net campus costs relative to using natural gas generators alone.

Does the strategy reduce net UCSD energy costs?

For UCSD, the primary criteria is whether the strategy does, or has the potential to, reduce net campus energy costs. Cost-effectiveness for the campus is essential to motivating interest in employing the strategy, providing a service, or investing in new resources or enabling technology. We are also interested in the size of the potential savings relative to total campus energy costs, and additional operational risks entailed in implementing the strategy (such as increased risk of a higher monthly billing determinant for demand charge calculations or increased O&M for campus facilities).

Is the strategy cost-effective compared to alternatives at today's prices?

For utilities and state regulators, the primary evaluation criteria is whether the strategy is cost competitive with readily available alternatives at current prices or avoided costs. We compare the total (TRC) cost of implementing the strategy with alternative resources or established avoided costs to determine if the strategy merits further consideration for utilities and policy makers. In this analysis, the fixed cost of the existing resources are considered sunk, and the incremental costs included in the TRC are only the variable operating costs associated with each strategy.

If not, is the strategy potentially cost-effective in the future?

Finally, if the strategy does not appear cost-effective at current prices or avoided costs, is there potential for the strategy to be cost-effective in the future? For example, load shifting may not be cost-effective in today's environment of excess capacity, but might be as the state moves closer to resource balance and RA costs increase.

A negative net cost metric satisfies the first criteria, showing that the strategy has lower total cost than the base case it is compared against. If the first criteria is not met, the second considers if a strategy is cost effective as compared to alternatives from a TRC perspective. The appropriate alternative for comparison depends on the category of strategies: the $/MW cost of PLS contrasted to current resource adequacy prices; the $/MWh cost of PV firming with campus resources contrasted with estimates of grid integration costs; and for the costs for the campus to provide regulation contrasted with today's wholesale prices. The third order criteria, applying only if the previous criterion are not met, explores how future prices or scenarios under which strategy would become cost effective.

4.4.3 Peak load shifting

4.4.3.1 *Base case and optimization approach*

The base case assumes normal UCSD operation, in which UCSD dispatches its resources (namely generators and TES tank) to minimize overall energy costs.

To model peak load impacts, we utilize the month long minimization version of the model. We make this choice because for this class of strategies, monthly peak load reductions and demand charges are of primary importance.

4.4.3.2 *No all-hours demand charge*

Under existing tariffs, the TES is not used to its full capacity due to the all-hours ('non-coincident') demand charge that frequently constrains the operation of the TES tank and/or the import of electricity in off-peak periods. If, for example, UCSD shuts down a generator or charges its TES tank at night, it could easily shift its overall peak demand to the off-peak period, increasing the MW demand billing determinant for the month.

UCSD is billed under SDG&E's AL-TOU rate schedule for commercial and industrial customers with maximum demands greater than 500 kW. The AL-TOU rate schedule has two demand charge rates an all-hours demand charge that applies to the peak demand in any hour, and an incremental "Maximum Demand at Time of System Peak" demand charge that is added to the all-hours demand charge if the customer's peak occurs during the on-peak period. For a customer taking service at the primary level, the all-hours demand charge during most of the period of analysis was $11.70/kW and the Summer on-peak demand charge was an additional $8.22/kW, for a total of $19.92/kW. UCSD owns its own substation and takes service at the transmission level, which has much lower demand charges. The all-hours demand charge is $4.02/kW and the additional Summer on-peak demand charge is $1.76/kW, for a total of $5.78/kW. The relatively small differential between the on-peak and all-hours demand charges makes it uneconomic for UCSD to shift load from on- to off-peak if it would increase the all-hours demand billing determinant for the month by even a small amount.

To quantify the impact of the all-hours demand charge on peak load shifting, we analyze a scenario where the all-hours demand charge is eliminated, and the on-peak demand charge is increased to include both the all-hours and on-peak demand rates. We do not evaluate other viable rate mechanisms that could be implemented to the same effect, but use this as an illustrative case. The rational for restructuring the all-hours demand charge for PLS customers is discussed in Section 5.2.4.

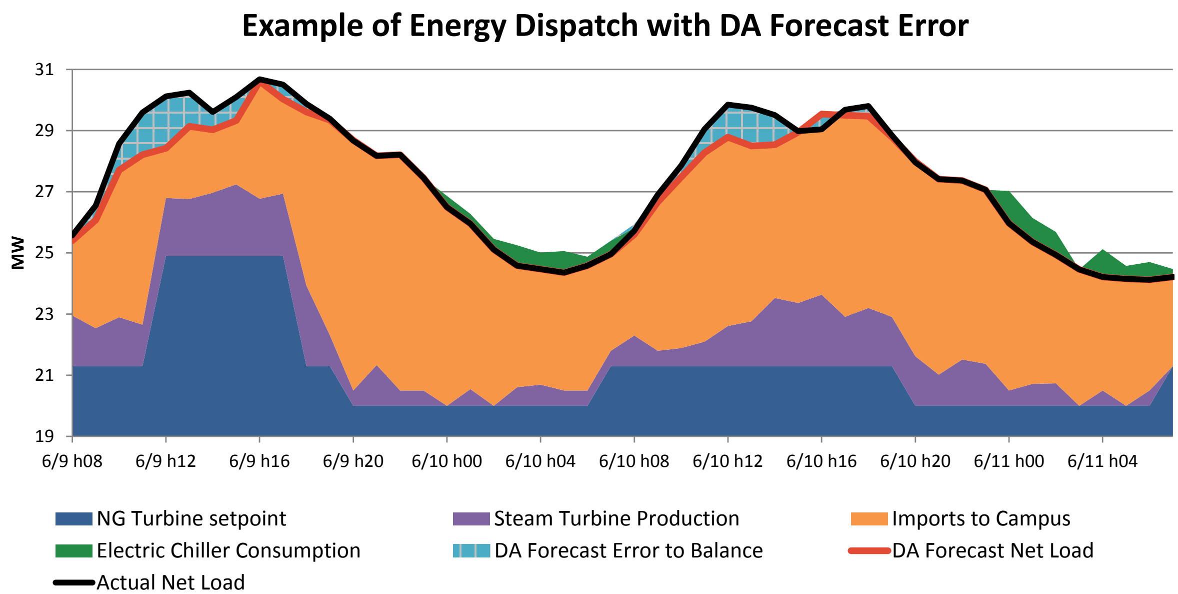
4.4.3.3 *Reduced peak window*

We evaluate a case with a reduced peak window of just 4 hours instead of the SDG&E on-peak period of 7 hours. Our intent is to determine if a shorter period would allow the TES to shift a reduced amount of load over a smaller peak period without increasing the all-hours demand charge during the off-peak period.

4.4.4 PV firming

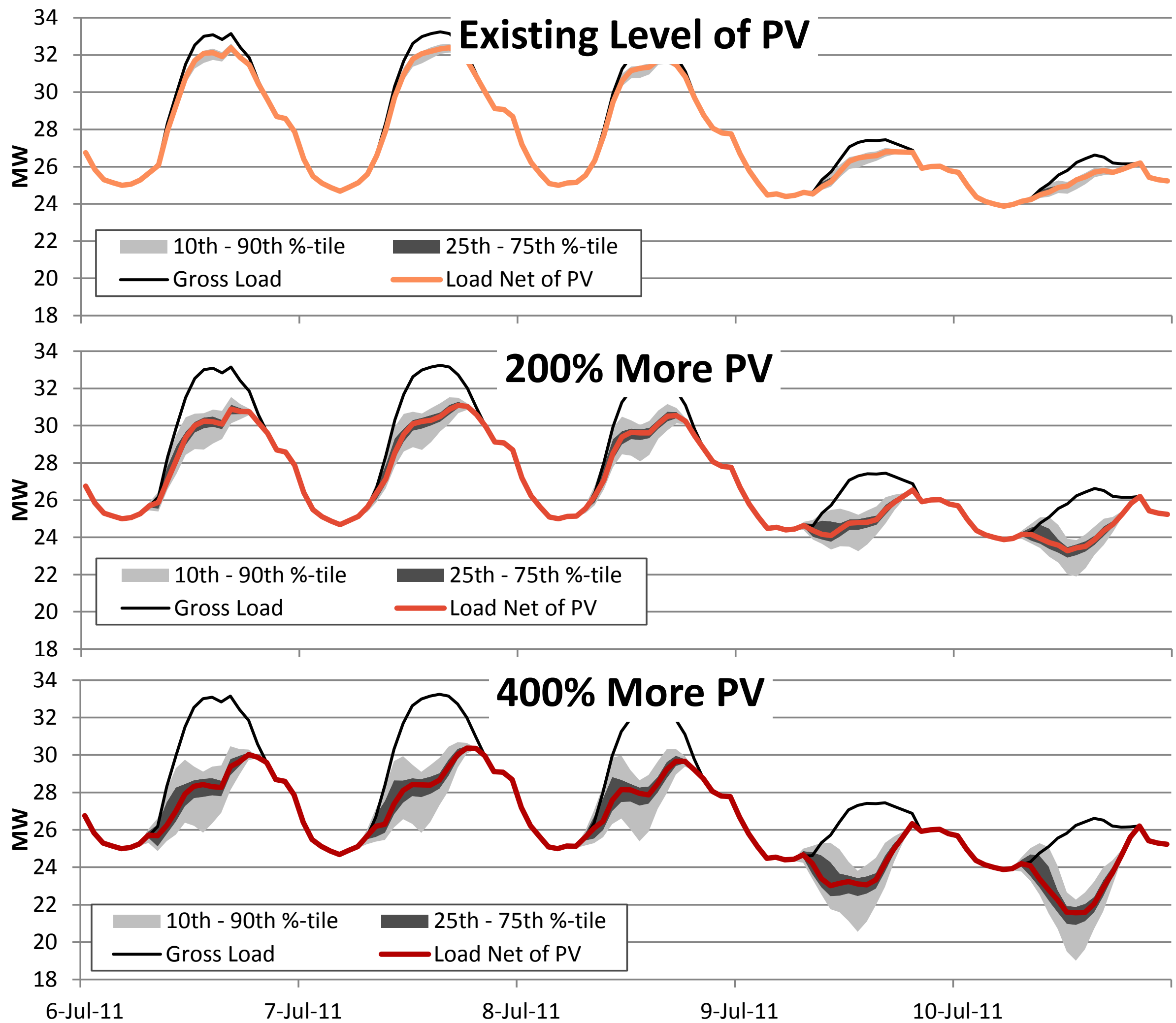
This second category relates to integrating UCSD's onsite solar generation. We explore how UCSD's own resources can be leveraged to integrate increasing levels of PV penetration, which is relevant for UCSD and more broadly. A key aspect of the PV integration challenge is addressing the error between the day-ahead forecast of PV production, which the campus would use to plan its dispatch, and the actual PV production. The forecast error can result in over-generation or unscheduled imports from the grid to make up for a shortfall in energy. Figure 4 shows an example of how real-time dispatch differs from the day-ahead forecast due to forecast error. In this example, the actual net load (shown in black) is higher than the DA forecast (shown in red) for most daytime hours. This is because the actual PV generation was lower than forecast (not shown). The difference (blue squares between the red and black lines) must be made up with imports from the grid that were not included in the DA schedule.

Figure 4: An illustration of PV forecast error arising from dispatch based on DA forecast of PV production (red line) which differs from actual PV production (black line).



Currently, there is no cost to UCSD for relying on the grid to make up for differences between the actual vs. DA forecast PV generation. The strategies analyzed here hypothesize either charging UCSD a penalty for deviations from the DA schedule or using campus resources to offset forecast error and maintain the DA schedule in real-time. The overall approach to analyzing these renewable integration strategies of correcting the DA forecast error of PV production, or "PV firming", can be thought of as consisting of two dimensions: strategies for firming PV output and levels of PV penetration. The first dimension of the analysis considers three different strategies addressing PV forecast error joined by a common base case. The second dimension considers how increasing PV penetration and associated increases in PV forecast error impact the different PV firming strategies. The forecast error associated with the existing level of PV penetration on the campus is small relative to total campus resource flexibility, with a maximum-forecast error of roughly 0.7 MW. Our analysis includes alternative versions of the campus where all resources on campus remain unchanged except for total installed PV, which we increase by 200% and 400% for different scenarios. Increasing campus PV penetration presents scenarios where forecast error represents a sizable portion of campus resource flexibility. Firming PV output becomes a planning challenge at these higher levels of penetration. The increase in forecast error with higher penetrations of PV is illustrated in Figure 5, which shows PV production's impact on gross load under three PV penetration scenarios for five days in July. The dark and light grey shaded areas show the range of uncertainty for the forecast error. The black line shows total (gross) campus electrical load and the colored lines show the net load after subtracting the on campus PV generation. Under current penetrations the difference between total and net load is relatively small, as is the uncertainty associated with the DA forecast error. At twice the current penetration, the forecast error to nearly 2 MW for the 10^{th} – 90^{th} percentile bounds in some hours. At four times the current penetration, the error increases to 5 MWs in some hours.

Figure 5: The impact of increasing PV penetration on load net of PV production with PV forecast error.



4.4.4.1 *Base case and optimization approach*

Base case: The case which serves as the common point of comparison for the various PV firming strategies contains no forecast error and can be thought of as perfect foresight of PV production. With this case the day ahead forecast of PV production, which is what the model uses to determine resource dispatch, is equal to the actual production. As there is no forecast error to correct there is zero cost associated with PV firming for this case. There is a distinct base case for each of the three difference levels of PV penetration.

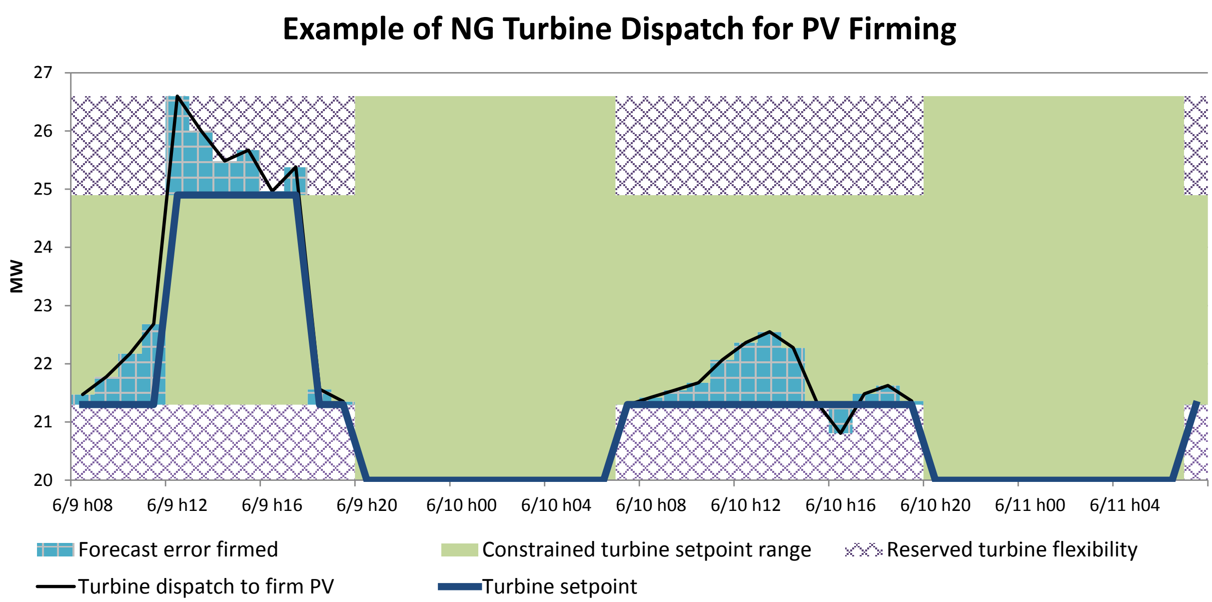
Optimization approach: We utilize the daily model for the PV firming analysis and apply it in two stages. We choose this implementation because, for the PV firming strategies, temporal variability in PV generation forecast error is a key driver. The first modeling step determines which resources are on when and for how long at each PV penetration level. The second step solves to minimize daily total cost implementing each strategy with the pre-determined on/off schedule. For simplification purposes, we do not model demand charges.

4.4.4.2 *Firm/Smooth PV generation with gas generation*

One mechanism for firming PV forecast error is to reserve the flexible capacity of the natural gas generators on campus to address this error. This first strategy effectively lowers the maximum and minimum operation levels of the campus's gas turbines during hours with PV production. The maximum/minimum operation level is changed so sufficient flexible capacity is reserved to correct the maximum over-forecast and under-forecast error that occurs in each month. The model solves for the gas turbine set point assuming PV production is equal to the DA forecast and adds constraints to reserve adequate flexibility to address PV forecast error. Ex-post calculations adjust natural gas costs to reflect gas generator adjustments from addressing PV forecast error.

Figure 6 illustrates the approach to constraining total gas turbine flexibility to correct for unknown forecast error. In Figure 6 the range of gas turbine set point available to the optimizer is indicated in green. During the daylight hours, the range of dispatch available to the generators DA is constrained to leave the remaining capacity (in white) available to balance forecast error in real-time. The solid blue line follows the dispatch solution from the optimization model in the day-ahead based on the PV forecast. The black line represents the actual dispatch of the gas generators which are firming the PV forecast error shown in blue. For most hours in this example, the generators are being dispatched upward to deliver more energy, compensating for undergeneration from the PV relative to the DA forecast.

Figure 6: An illustration of using NG generator flexible capacity to correct PV forecast error.



4.4.4.3 *Firm/Smooth PV Generation with gas generation and steam turbine*

The gas generation and steam turbine strategy for PV firming is identical to the gas generation firming strategy described above with the addition steam turbine flexibility to firm PV forecast error. The sum of reserved flexibility from gas generators and the steam turbine must equal the maximum monthly forecast error. Natural gas usage for firming is accounted for in strategy total cost. Steam usage for firming is assumed to be the maximum needed for the reserved flexibility and is reflected as an opportunity cost in the optimization.

4.4.4.4 *Two-part rate*

The third strategy for firming PV error assumes that the DA forecast is equal to PV production for solving the dispatch but does not allow for reserving flexibility from any campus resource. This strategy assumes that the campus participates in a novel 2-part tariff, which consists of the current tariff along with a renewable integration penalty charge for error in forecasted PV production. For our analysis we assumed the penalty would be based on the estimated renewable integration cost of $8/MWh of production (Milligan et al., 2009) which in the UCSD context equals roughly $31/MWh of forecast error. With the 2 part tariff strategy the campus can firm PV error by leaning on the grid. However all forecast error firmed with the grid incurs the $31/MWh penalty. UCSD is not paid for any inadvertent exports to the grid and UCSD pays the hourly energy price for increased energy imports above the day-ahead schedule .

In general, estimates of renewable integration costs are based primarily on system level operating costs. Distribution system integration costs, whether fixed and variable, are not as well characterized to date, and cost estimates are not widely available. An important limitation of this study is that the distribution system upgrades needed to support the higher penetrations of PV modeled for UCSD is not considered. As further consensus develops regarding the quantifiable distribution system costs related to high penetration, distributed PV, those costs will need to be incorporated retail rates, payments for PV generation and in the cost-benefit analysis of integration strategies. Such analysis will be critical, as the greatest costs and barriers to distributed PV are expected on the distribution system.

4.4.5 **Support grid operation**

The third set of strategies moves beyond firming renewable resources on campus to using campus resources to support grid operations. A number of initiatives are investigating new market designs (e.g. CAISO Regulation Energy Management with non-generation resources and Flexi Ramp product), flexible capacity needs (e.g. CPUC and CAISO flexible capacity procurement) and renewable integration issues in general.

Because system needs and product definitions are evolving rapidly and the subject of several intensive modeling efforts, we do not attempt to predict future market product definitions or prices that might be available to UCSD. Instead, we use an established market, frequency regulation, as an illustrative case study. Frequency regulation is (currently) has the highest prices of the AS markets and is frequently cited as needed for renewable integration.

In CAISO (and ERCOT) separate markets exist for regulation up and regulation down. This allows resources to bid separate quantities and prices in the up and down markets, unlike other ISO's. Regulation up entails the commitment to increase generation (or reduce load) to the grid and regulation down the commitment to reduce generation or increase load. We use historical hourly frequency regulation prices from the CAISO to quantify the value of frequency regulation over the period of analysis. Because approximately 85% of regulation is procured in the day-ahead market, we use day ahead rather than real-time prices.

There will soon be two options for non-generator resources to participate in frequency regulation markets. The first is Regulation Energy Management in which the CAISO actively monitors the state of charge (SOC) for a storage resource or the dispatch operating target (DOT) for participating load. The CAISO preferentially dispatches each resource to maintain the SOC or DOT such that the resource can provide the full amount of regulation bid. The other alternative is participating as a Dispatchable Demand Resource (DDR) in non-REM regulation. In response to FERC Order 755, the CAISO is also implementing pay-for-performance regulation, which will account for the speed and accuracy of response in paying for mileage.

Our analysis most closely approximates the second (DDR) alternative. We assume that UCSD must be able to provide a full hour of regulation for the MWs bid, and may earn revenues in the energy market. No pay-for-performance enhancements are included.

In the next sections, we describe the base case and four additional cases we use to illustrate the costs and benefits of providing frequency regulation. We deliberately use five step-wise cases, each with increasing complexity, to inform our intuitive interpretation of the results. The quantity that can be bid is a function of the resource dispatch. We performed analysis on our limited regulation signal data set to map it to our hourly dispatch. Our preliminary modeling included multiple optimization passes, starting with optimal dispatch based on expected mileage and then optimally re-dispatching based on our constructed regulation signal, but computational limits required we neglect mileage for running the grid support strategies.

4.4.5.1 *Base case and optimization approach*

Base case: The base case used to evaluate the provision of frequency regulation is similar to the base case used for peak load shifting, which is an optimization of campus resources under their current tariffs. The key differences are that the monthly all-hours demand charge is not included in the optimization, and the optimal level of on-peak demand for the hourly dispatch is assumed to be 5 MW. Excluding the all-hours demand charge reduces the complexity of the optimization and substantially decreases model run times. Furthermore, in practice, UCSD would simply not offer regulation in hours where there was a possibility that doing so might increase the monthly demand billing determinant. Because this would be limited to a few hours a month for the all-hours demand charge, we do not expect this would significantly affect the economic results presented here. There is a greater possibility of this happening with the on-peak demand charge, so it was necessary to maintain some form of on-peak demand cost. Determining the optimal level of on-peak demand is at the same time as the optimal regulation bidding exceeded the computational ability of our solver. As an approximation we set the on-peak level of demand to the same value, 5 MW, for all of the strategies.

Optimization approach: The dispatch and flexibility of campus resources are the important consideration for the grid support strategies. We apply the daily optimization model in two steps. All grid support cases share a common on/off schedule which is solved in the first step. In the second step, we include the on-peak demand charge but exclude the all-hours demand charge for simplicity. We include the demand charge because it is an important consideration for grid support. There are tradeoffs between reserving generation capacity for offering grid support and the demand charge increases that higher electricity imports may trigger. Rather than utilize the month-long optimization to solve for an optimal demand level, we choose a reference demand level (based on observation of historical demand levels) as the starting point for all grid support cases. The optimizer assumes that only on-peak imports beyond this pre-selected level incur the demand charge.

4.4.5.2 ***Fixed, simple regulation***

We start with a very simple strategy using just the natural gas generators. The generators are allowed generators to bid equal amounts of regulation up and down at the maximum quantity of 3.3 MWs. If the natural gas generators are running, they may operate between 20 – 26.6 MW to provide energy and reduce campus imports or provide regulation. If the optimizer choses the later, the generators operate at a DOT of 23.3 MW to offer 3.3 MW of Reg Up and 3.3 MW of Reg Dn. The cost to the campus of providing regulation is the lost opportunity to reduce imports by generating a full 26.6 MW during higher priced hours, or to increase imports when prices are low. The benefit to the campus is earning revenue in the regulation market, for which the average price were $6.18/MW for Reg Up and $6.03/MW for Reg Down over the period of analysis.

4.4.5.3 ***Simple regulation***

Our simple regulation case relaxes the constraints somewhat and allows the optimizer to choose any bid level between 0 and 3.3 MW. The natural gas generator is still the only resource, and it must still offer the same quantity in the up and down direction. Bidding simple regulation requires the generators to operate at a set point which leaves sufficient flexibility to meet the bid quantity, for example a 2 MW bid would require a set point between 22 – 24.6 MWs so the generators could increase generation by 2 MW up to 26.6 MW or down 2 MW to 20 MW.

4.4.5.4 *NG generator based regulation*

The third case uses the natural gas generators to provide regulation, but the optimizer is now free to bid different quantities in the up and down direction. This one seeming minor change increases the flexibility of the generators in offering regulation substantially. In the above cases, if the generators are operating at their minimum or maximum levels, they cannot provide any regulation. In this case, the generators operating at the minimum level of 20 MWs can offer 0 MW of Reg Dn and 6.6 MW of Reg Up. The results in the next section show that the quantity of regulation bid into the market increases significantly in this case.

4.4.5.5 *All campus resources regulation*

In this final case, the steam generator and electric chillers may offer regulation along with the natural gas generators. The steam turbine increases the maximum generation that can bid into the regulation market. The electric chillers add load that can provide additional Reg Down, or decrease load to provide additional Reg Up. Together the combined resources can now provide ~ 13.5 MW of Reg Up or Reg Dn separately.

5 Project Outcome

5.1 Base case development

5.1.1 Illustrative dispatch

We present the hourly dispatch results of the base case analysis that illustrates the value of utilizing different levels of UCSD DERs. Examples of the hourly dispatch in the month of August are shown in Figure 7. These three graphs show how the dispatch of campus resources changes as additional DERs are added to the optimization.

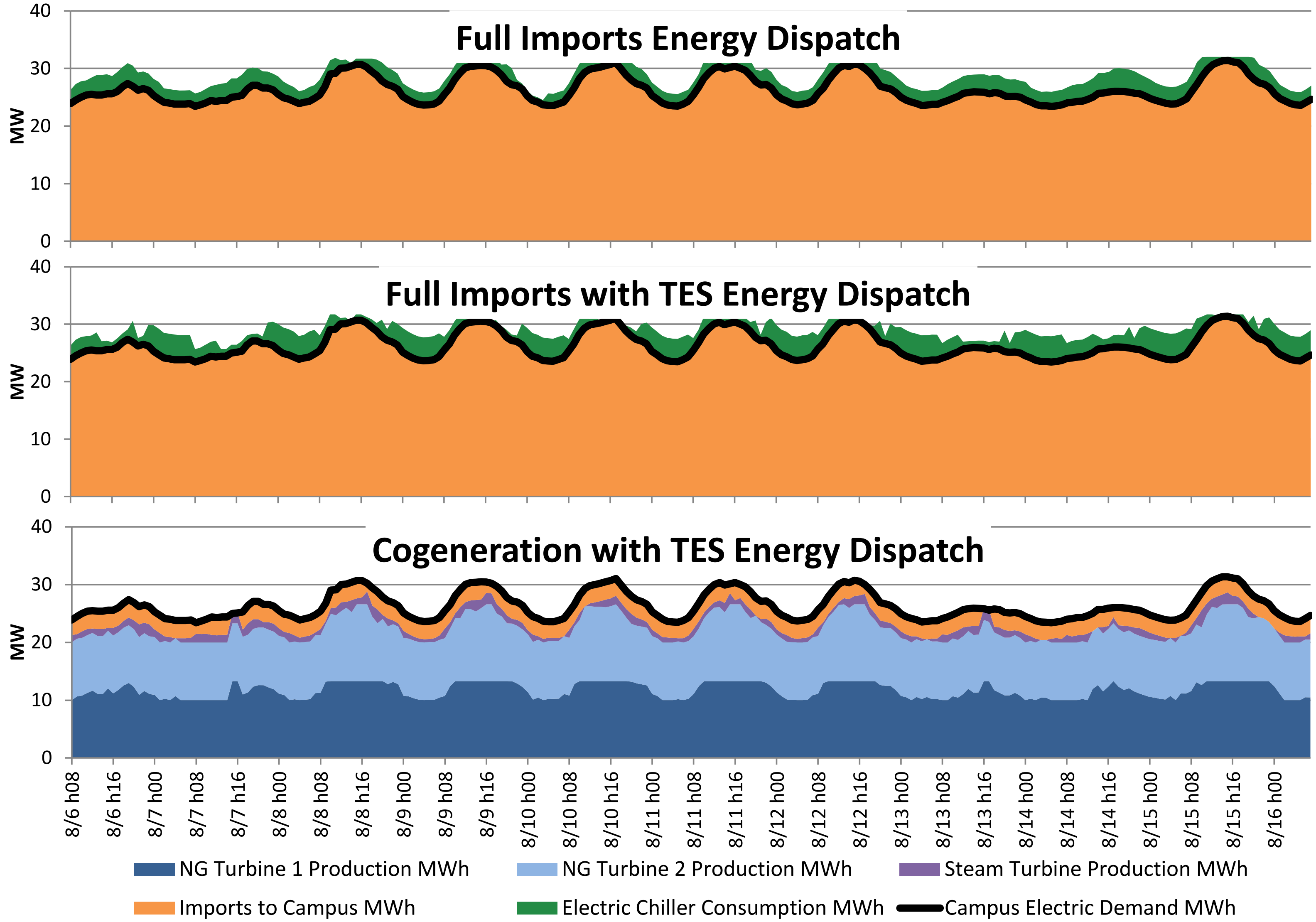
The first panel (Full Imports) shows the dispatch without cogen or TES – campus load is served entirely by electricity imports from the grid (shown in orange). The electric chillers (green) are running throughout the day and most nights to provide cooling. While it is possible in this case for the campus to provide cooling from the steam chillers by generating steam with the boilers the results show the electrical chillers are still consistently relied on given their comparative cost advantage over natural gas converted to steam converted to chilled water. There are a few hours where we see electrical chiller use flattening or decreasing, but these are hours with high energy prices and demand just shy of the optimal level. In these few hours the steam chillers provide cooling, effectively fuel switching to natural gas.

The middle panel (Full Imports with TES) shows how the dispatch changes with the addition of the TES system. The TES tank displaces some of the cooling from steam chillers during high price energy hours in the full imports case – the electrical chillers fully turn off during some afternoons to avoid on-peak demand and higher energy charges and the model discharges stored chilled water instead. In the evenings we see the model ramp up electric chiller use to recharge the TES. This leads to the TES only case primarily saving boiler natural gas, and using slightly more electrical energy to recharge the TES as compared to the full imports case.

Both of these are intuitive uses of the electric chillers together with the TES given the diurnal differences in energy prices and the on-peak demand charge.

The final panel (Cogeneration with TES) shows the cogeneration together with TES case. This case is markedly different from the other cases in that the cogeneration substantially decreases the level of imports, and the additional steam from the cogeneration plant together with the TES effectively replaces the electric chillers for cooling.

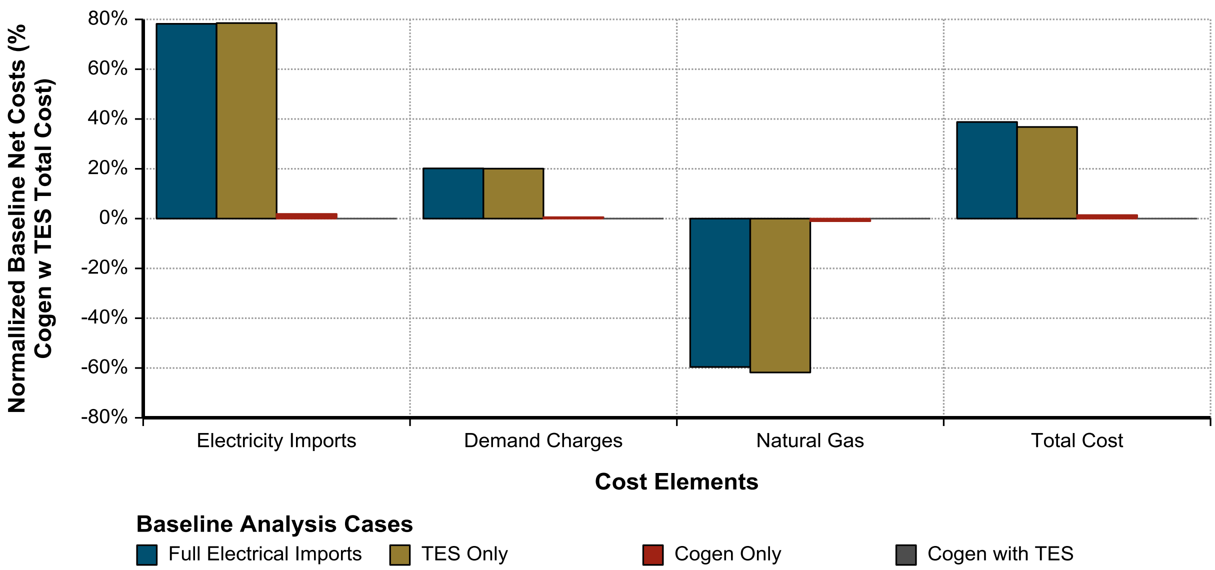
Figure 7: Hourly dispatch examples for the stepwise baseline analysis, each graph shows progressively more DERs.



5.1.2 Monthly cost impacts

With the stepwise progression we established the baseline case for operation of campus resources, including cogeneration and TES. Throughout the remainder of the report we present the costs for each strategy as a percentage of the base case costs. This presentation of costs for the stepwise analysis building up to the base case is shown in Figure 8, broken out by cost element (Electricity imports, demand charges, natural gas and total). Positive percentages above the x-axis show that the strategy costs are higher than the base case, negative percentages show that costs are lower.

Figure 8: Percentage change in cost components relative to total cost of the cogeneration with TES strategy.

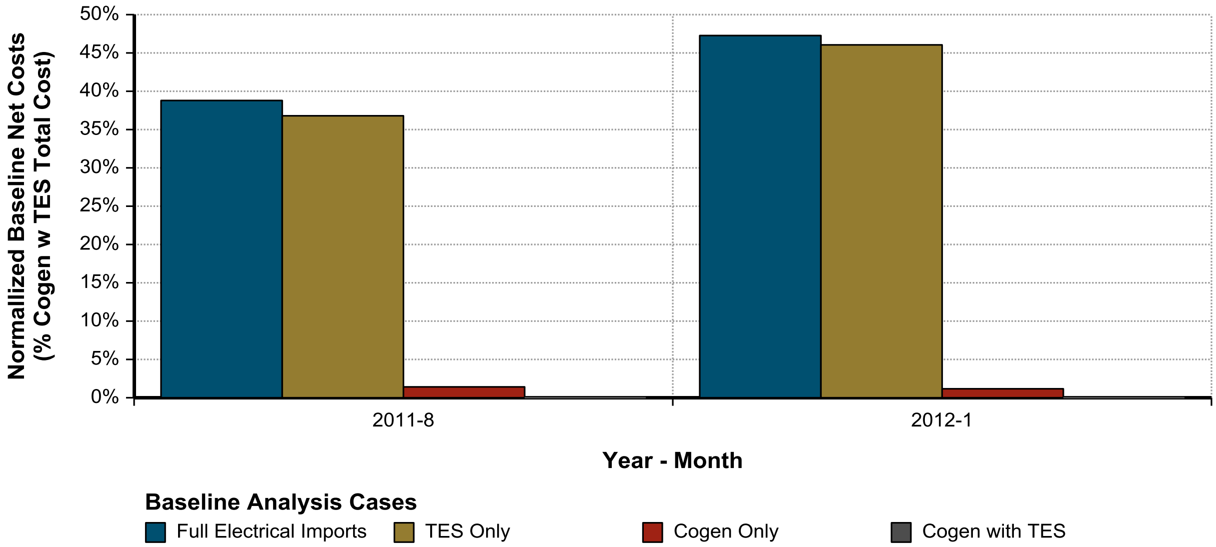


Compared to the base case with cogeneration and TES, the full imports case has higher costs for electricity imports, lower costs for natural gas and ~40% higher total costs. With TES, natural gas consumption is reduced and replaced with electric chillers. This increases electric imports, but shifts them to off-peak hours, so electricity import costs remain virtually unchanged. Total costs are only slightly lower than the full imports case. With cogen, but without TES on campus production of electricity the import and demand charge costs decrease and natural gas costs increase significantly compared with the prior two cases. Finally, with TES and cogen together, the costs are reduced still further, by ~1% as compared to cogen alone.

5.1.3 **Monthly results and summary**

Figure 9 presents the August and January net costs of the stepwise cases, relative to the cogeneration with TES base case. We see that each step adding resources reduces costs to the campus. This intuitive result serves as a validation for the cost benefit modeling approach.

Figure 9: The net cost of baseline analysis cases normalized to the cogeneration and TES case.



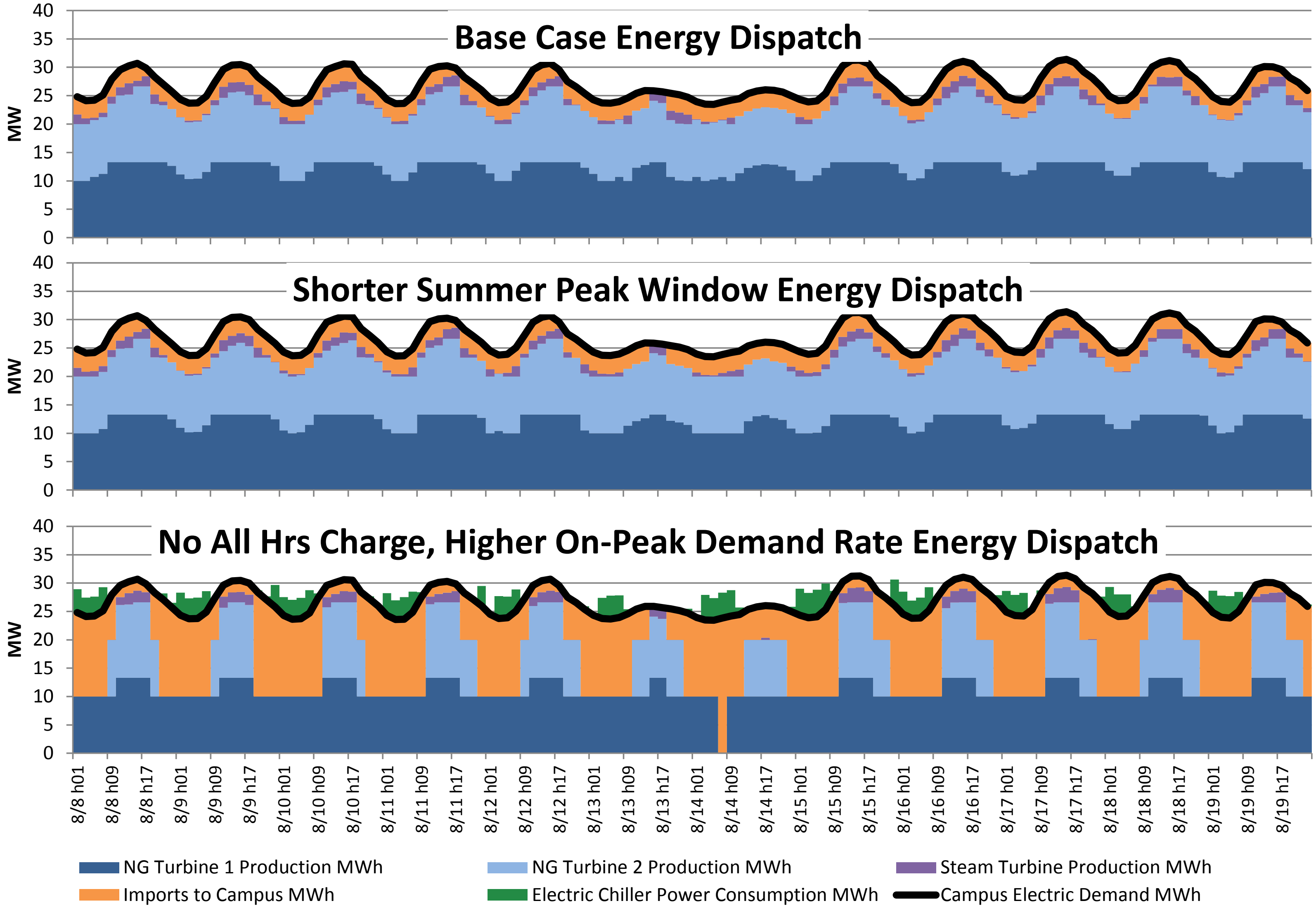
5.2 Peak loading shifting

5.2.1 **Illustrative dispatch**

Figure 10 presents a subset of modeling results for a number of days in August 2011 for both PLS load shifting strategies and the peak load shifting base case. The contrast of dispatch for each scenario can be seen across the hours of this portion in August. The shorter summer peak period strategy results in a minor change in dispatch as compared to the base case. While imports consistently remain low over all-hours for both the shorter peak and base case, the gas turbines are dispatched at a marginally lower level in some hours in the shorter peak strategy.

The dispatch for the no all-hours demand charge strategy differs greatly from the base case dispatch. Without the penalty for increasing load in the off-peak, the ‘no all-hours demand charge’ dispatch frequently shuts off a natural gas generator at night and recharges the TES tank with electric chillers to take advantage of low energy prices. Eliminating the all-hours demand charge and raising the on peak demand markedly increases resource flexibility during off peak hours.

Figure 10: Dispatch examples for the PLS base case along with the case where there is no all-hours demand charge and the peak demand rate has increased to incorporate the old all-hours demand rate.

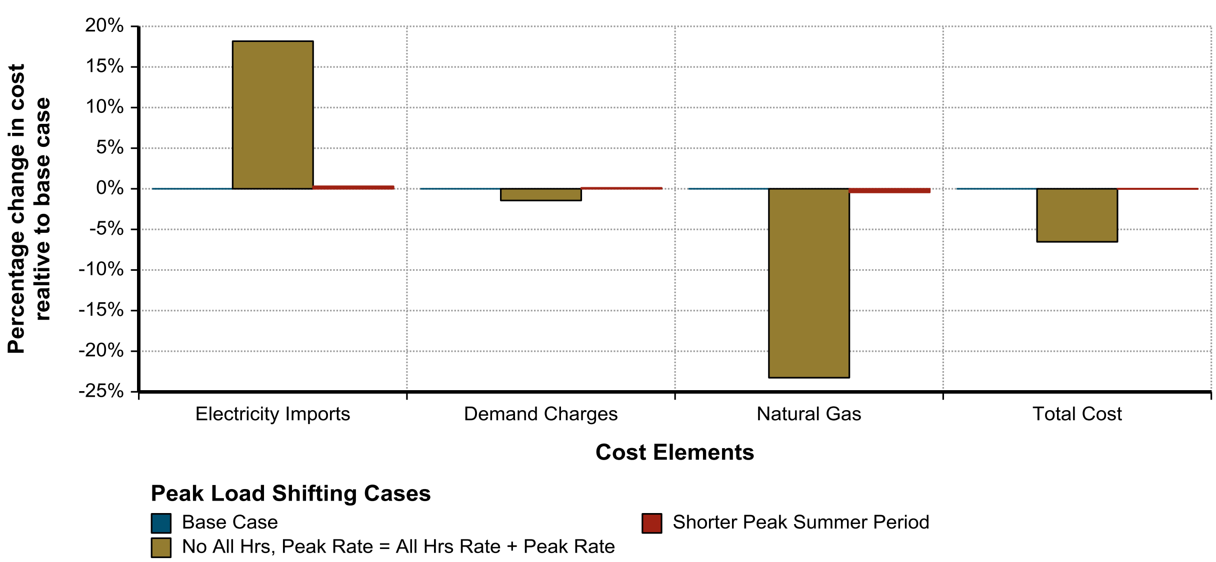


5.2.2 Monthly cost impacts

The impact of the two PLS strategies compared to the base case for each cost component is shown for the month of August in Figure 11. The strategy which eliminates the all-hours demand charge shows a sizable change in cost impacts, increasing expenditures on electricity imports by more than 15% while decreasing demand charge and fuel expenditures. The no all-hour demand charge strategy reduces campus costs by ~ 7%. These savings are also a revenue loss to the utility of more than 20%. However, fixed costs appropriately allocated to UCSD could be recovered via alternative mechanisms that do not discourage peak load shifting.

The shorter peak period strategy also results in greater electricity imports but by less than a 0.5% increase. This strategy also slightly increases demand charge costs while decreasing gas use. The impact for the shorter peak period strategy is minimal reduction in total cost, 0.02% savings, where increases in electricity and demand costs are offset by reduced natural gas use.

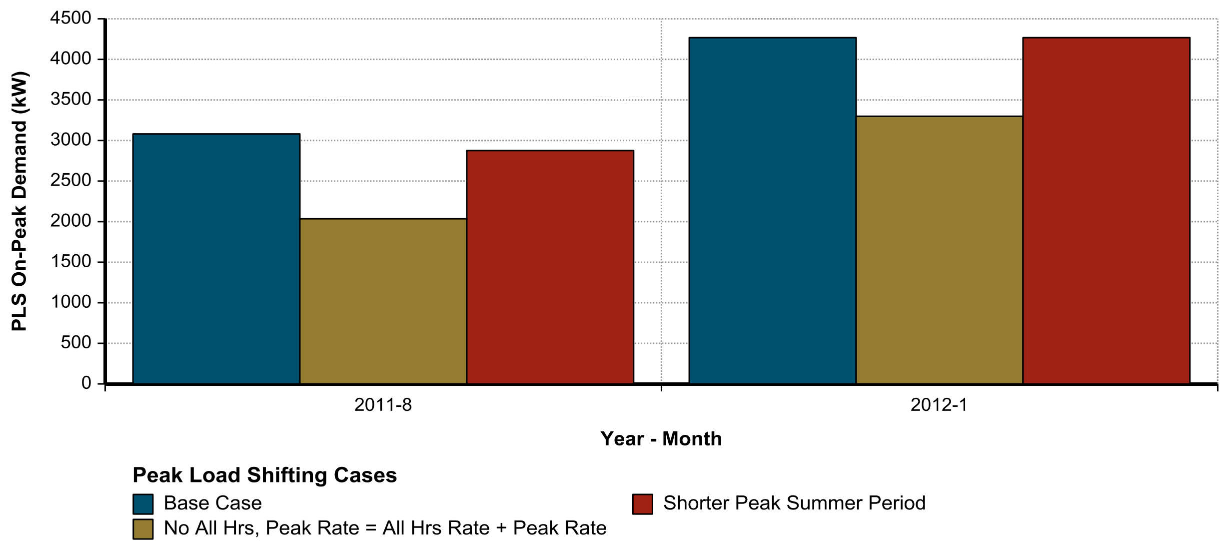
Figure 11: Percentage change in cost relative to total base case costs.



5.2.3 Monthly results and summary

The maximum level of on-peak demand for each of the strategies in the PLS category are shown in Figure 12. In August, both of the PLS strategies reduce on-peak demand, by over 1 MW when eliminating the all-hours demand charge and increasing the on-peak demand charge and about 0.2 MW by shortening the summer peak period. In January the no all-hours demand charge strategy reduces on-peak load by just under than 1 MW while the shorter summer peak period has no impact on winter months.

Figure 12: On-Peak demand for PLS strategies in August and January.



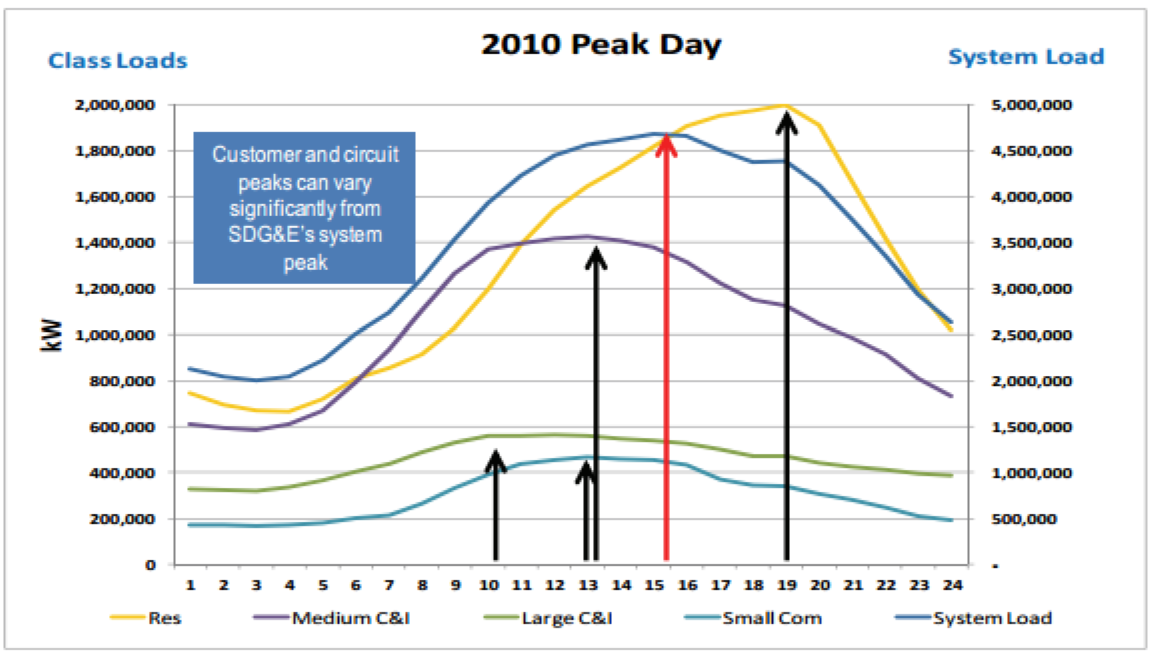
Removing the all-hours demand charge reduces the cost to campus of shifting peak load by $36 per kW in August and $16/kW in January. The shorter summer peak period saves only about $1 per kW of on-peak reduction.

5.2.4 All-hours demand charges

Our analysis of historical campus loads and resources showed that the all-hours demand charge frequently limits off-peak charging of the TES tank. In some cases, fully recharging the TES during off-peak hours would cause an increase to the maximum demand billing determinant for the month; that is the UCSD off-peak demand would exceed their previously set on-peak demand MW for the month. This leads to a counter-productive result for a customer with load-shifting capability wherein UCSD is prevented from reducing peak loads to the full extent possible.

The SDG&E all-hours demand charge is designed to reflect demand related distribution costs incurred to serve the customer, regardless of when the peak demand occurs. For example, distribution feeders are sized to meet the simultaneous peak demands of all existing (and some future) customers on the feeder. The timing of the feeder peak can vary significantly depending on the customer class served, as illustrated in SDG&E's rate case (Figure 13).

Figure 13: 2010 SDG&E peak day loads



Source: (San Diego Gas and Electric, 2012 General Rate Case, Phase 2)

The figure shows the aggregate class demands on the day of the SDG&E system peak. The system peak occurs at 3 pm, yet the individual classes peak between 10 am and 7 pm. Similarly, the peaks on SDG&E's distribution equipment will occur at different times depending on the mix of customers served by the equipment. For example, feeders and substations serving primarily residential customers will likely peak in the early evening, while feeders and substations serving medium commercial customers will likely peak in the middle of the day. The SDG&E all-hours demand charge is designed to capture these kinds of timing variations.

PLS customers, however, present a specialized case that differs from typical loads in that the customer peak can be shifted to super off-peak hours. Regardless of the customer composition on a distribution feeder or substation, it is highly unlikely that a peak demand would occur in super off-peak hours, which argues for a revision of the all-hours demand charge to exclude the super off-peak period. SDG&E recognizes this fact in its 2012 GRC Phase 2, and identifies it as an area for further investigation:

> "Excluding the super off-peak period from the recovery of some level of distribution demand costs increases pricing accuracy in that energy use during that time period is typically low and generally does not create additional distribution demand costs. Limiting the collection of distribution demand revenues to time periods in which additional load can create additional costs increases the accuracy in retail price signals through marginal cost methodologies."
>
> (Doc #254237, CY-7, http://www.sdge.com/sites/default/files/regulatory/Ch-1-Yunker.pdf)

To be sure, some fraction of the distribution costs may be driven by individual customer peaks, rather than simultaneous aggregate customer peaks. Those costs would appropriately remain an all-hours demand charge, but such costs are generally a small fraction of distribution demand costs.

For PLS customers, the all-hours demand charge leads to a counter-productive and counter-intuitive result that limits the peak load reduction and import of inexpensive imported electricity (and wind overgeneration) in the off-peak. In the interim, while SDG&E conducts further investigation of the super off-peak demand cost pricing, we recommend that PLS customers' all-hours demand charge be revised to only use the

PLS customer's monthly peak demand between the hours of 5am and midnight (just my guess here).

5.2.5 Cost-effectiveness tests for restructuring of all-hours demand charge

The cost reduction for UCSD has two components. One is the reduction in commodity costs for electricity and natural gas. As a direct access customer, UCSD's commodity costs are essentially the same as the wholesale prices that would be charged to SDG&E. Therefore any savings by UCSD are roughly equivalent to the TRC benefits for the commodity portion of their bill. Considering just the commodity impacts, the TRC benefits are roughly $38/kW shifted for August. Using the E3 DER Avoided Costs, which includes a ~40% and ~36% allocation to August of system and T&D capacity costs respectively, the full TRC benefit is ~$85 per kW shifted.[7]

The rate impact is more complicated. In this strategy, UCSD is increasing electricity imports and decreasing natural gas consumption. With regards to the SDG&E bill for deliver charges, this increases the electric revenue but reduces natural gas revenue. Expressed on the basis of kW shifted, the electric bill increases ~$8/kW and the gas bill decreases ~$7/kW, for a net impact of a ~$1 bill increase. The utility as a whole is receiving more revenue, but with a positive impact for electric ratepayers and a negative impact for gas ratepayers.

This is an illustrative case only, the restructuring of the all-hours demand charge would require further investigation. We also are only considering the incremental costs of encouraging additional load shifting with existing equipment – no costs for new equipment are included. Still, this example for the month of August suggests that restructuring the all-hours demand charge for PLS customers could be beneficial from a TRC and ratepayer (RIM) perspective. The electric and gas ratepayer impacts are on the order of $7/kW shifted with a net impact of just $1/kW. Just the commodity TRC

[7] Calculation performed by E3 using SDG&E's DR Reporting Template with PLS Ver. 7-27-12 spreadsheet using E3 Avoided Costs

benefits (which are also a benefit to the utility in reduced procurement costs) are \$38/kW. With capacity benefits added, the total TRC benefits are more than \$80/kW. The benefits to the utility and its ratepayers outweigh the lost revenue substantially, and presumably rates could be restructured in such a way as to reduce or eliminate revenue losses even further.

5.3 PV firming

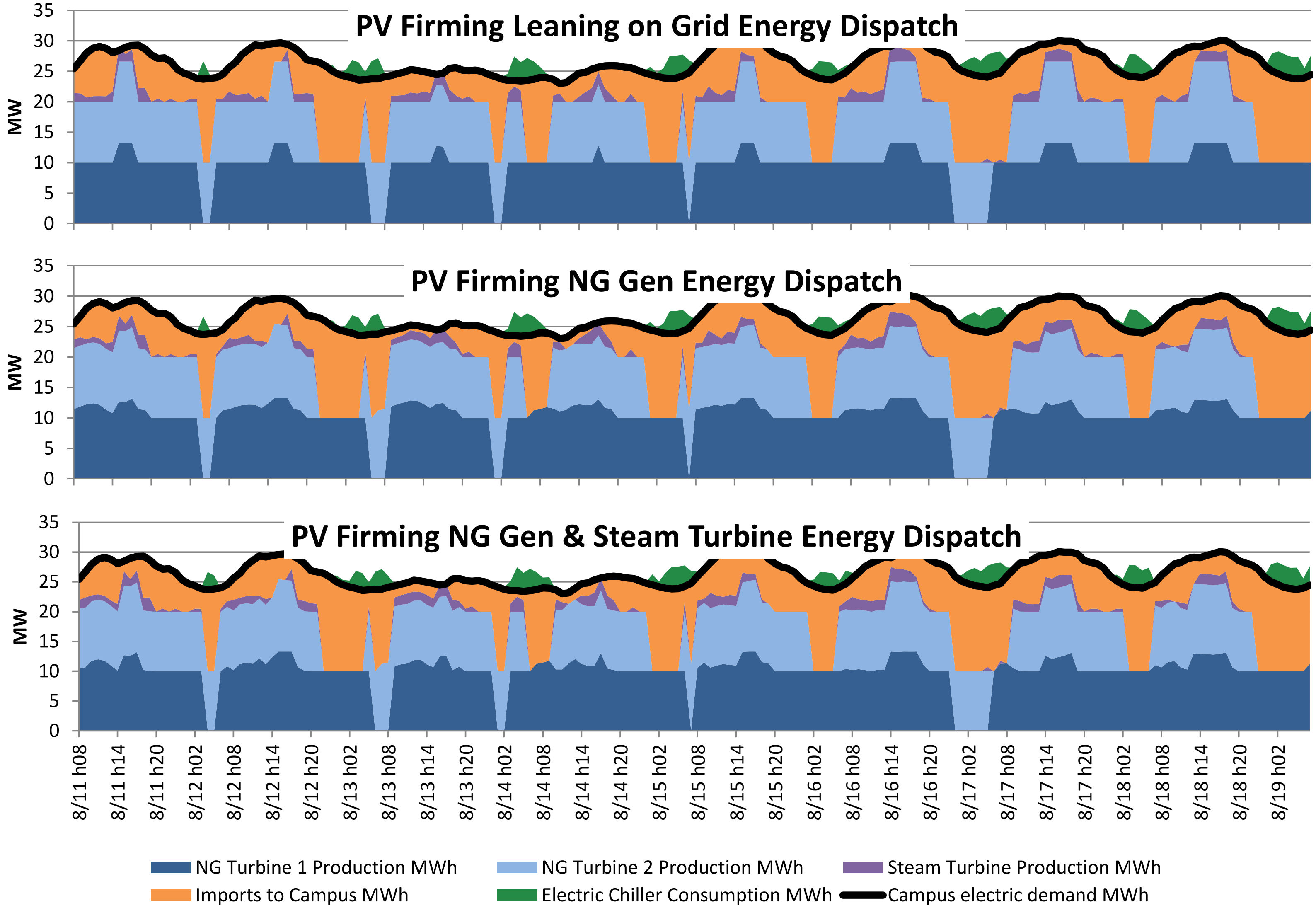
5.3.1 **Illustrative dispatch**

The hourly dispatch from the optimizer for the three different PV firming strategies during a portion of August are shown in Figure 14. The upper panel is the dispatch for the 2 part tariff strategy where imports are used to compensate for the error between the DA forecast and actual PV output. The middle panel is the dispatch for the natural gas generator firming strategy using the gas turbine (instead of imports) to compensate for forecast error. The lower panel presents the natural gas generators together with the steam turbine firming strategy where again resource production has been adjusted to correct for error.

The key comparison in the dispatches is between the 2 part tariff strategy and the two remaining strategies. The strategies that firm error using UCSD resources require reserving ~ 3 MW of flexibility. Despite this reduction in available campus generation capacity, the overall dispatch is very similar to the 2 part tariff strategy. The main difference between the grid firming strategy and the campus resource firming strategies is that during some afternoon hours when net campus demand is high, the 2 part tariff strategy has lower levels of imports. Since the 2 part tariff strategy does not restrict campus generation capacity to reserve flexibility, it has more capacity to decrease costly on-peak energy imports. In other hours, even with the reserved flexibility, the campus resource based firming strategies have slightly lower imports.

We observe differences between the NG generator strategy and the NG generator with steam generator strategy. Reserving steam turbine flexibility incurs no direct fuel cost, but it limits the available steam that could be used to meet cooling needs. In Figure 14 we see some hours in the morning where using the steam turbine to firm forecast error results in electric chillers staying on where in the NG generator support case the chillers have turned off for the night. Running the chillers more for the NG generator with the steam generator strategy results in additional electricity demand as compared to the NG generator only strategy.

Figure 14: Examples of energy dispatch for three different formulations of firming campus PV

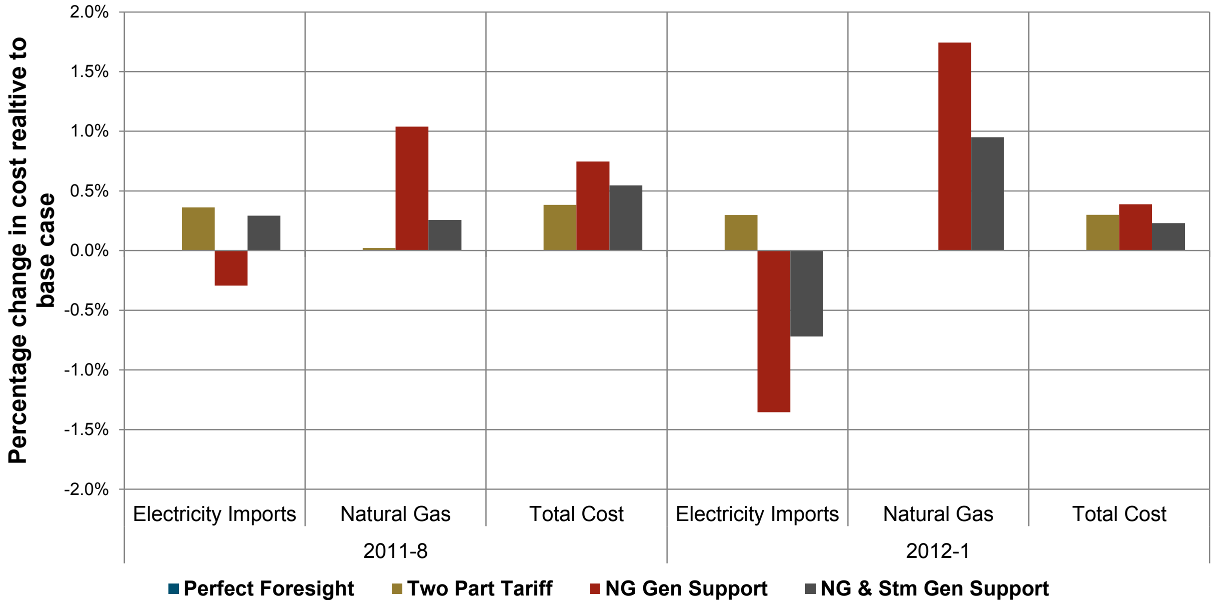


5.3.2 **Monthly cost impact**

The impacts on monthly cost components for the PV firming category are shown in Figure 15 for August and January. The 2 part tariff strategy incurs ~ 0.3% higher electricity import costs (include penalty payments) and negligible increases in natural gas costs for both months. The increase in electricity imports is higher for the grid leaning strategy than the other strategies.

The natural gas generation firming strategy shows savings in electricity imports relative to the base case, but those savings are overwhelmed by increased natural gas costs making total costs increase in both months. The NG generator and steam turbine strategy has increased natural gas use and increased total costs in both months, but decreased electricity imports in January and increased electricity imports in August. The likely reason for the change in sign is the cooling demand in the summer makes the opportunity cost of using steam to firm PV production higher than it is during the winter. Decreased steam in August leads to greater reliance on electric chillers and higher electric import costs. Even with the increase in electric costs in August, the NG generator with steam turbine strategy has a smaller increase in total cost than the NG generator only strategy due to a smaller increase in natural gas costs.

Figure 15: Percentage change in cost of firming strategies normalized to base case total cost.



5.3.3 Monthly results

All the PV firming strategies have positive net costs but with varying levels. With a common base case it is possible to convert the net cost metric for each strategy into a more intuitive implied cost of firming PV forecast error with net cost in the numerator and energy in the denominator. The implied cost of firming can be calculated in two ways: the implied cost of firming per MWh of *error* (Figure 16) and the implied cost of firming per MWh of *production* (Figure 17). Because the DA forecast error is much smaller than the total PV generation, the implied cost per MWh of error is higher. However the relative difference between strategies remains constant for both calculations.

Based on Figure 16 and Figure 17, the NG generator strategy is the most expensive of the three strategies in both August and January. Supplementing the flexibility of the NG generators with the steam generator allows the optimizer to find less expensive solutions in both of these months. The implied cost of the NG generator with steam generator strategy is close to the 2 part tariff strategy cost, slightly higher in August and slightly lower in January. These results indicate that firming with campus resources is at best marginally cost-effective. However, quantifying local, distribution system impacts could increase the benefits significantly and warrant further consideration.

Figure 16: Implied cost of firming PV forecast error on a MWh of error basis.

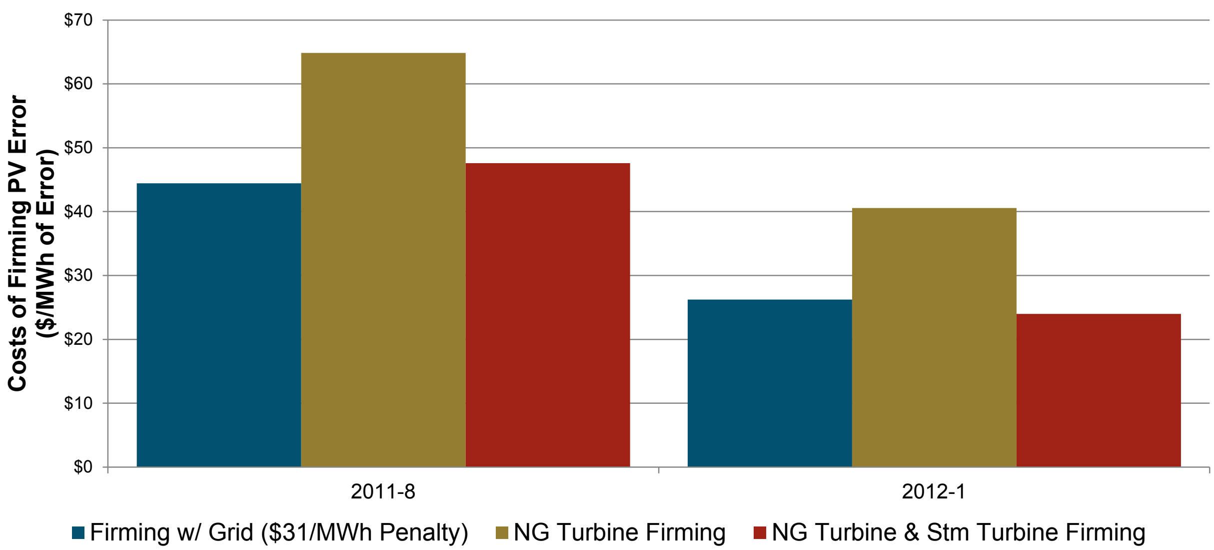
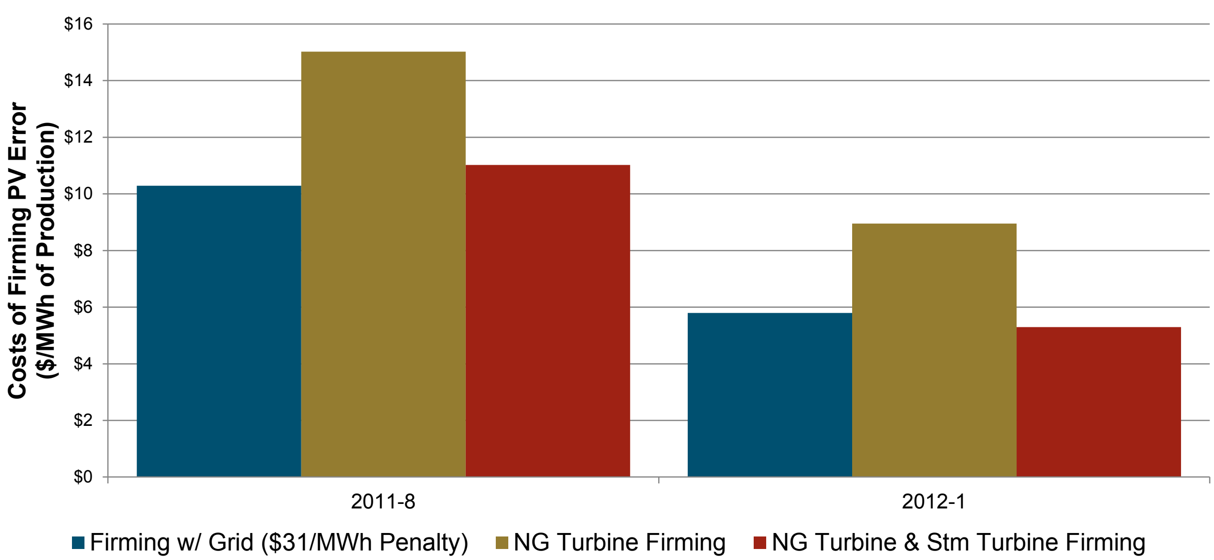


Figure 17: Implied cost of firming PV forecast error on a MWh of PV production basis, note the change in scale on the y-axis compared to the previous figure.



5.4 Support grid operation

In this final results section, we show the dispatch and costs and benefits to the campus for providing regulation.

5.4.1 **Illustrative dispatch**

The dispatch of campus resources for three of the regulation cases are shown in Figure 18. The first panel is the simple regulation case where the natural gas generators must bid the same quantity in the up and down direction, but can choose between 0 – 3.3 MW. The middle chart shows the natural gas generators free to offer separate quantities in the up or down direction. The final chart shows the full suite of resources, natural gas generators, steam generator and electric chillers providing regulation.

In contrast to the two prior strategies, the key result is the similarity in the resource dispatch for all three scenarios. The dispatch is similar in all cases, with some additional imports for electric chiller consumption in the last case.

Although the quantity of regulation offered in each case changes, the dispatch of campus resources does not. With increasing flexibility in market rules and the resources offering regulation, the optimizer takes further advantage of the opportunity to earn revenues in the regulation market (Figure 19), but does not alter the dispatch of campus resources to do so. The potential revenues from regulation as compared to total campus costs presented in the next section will demonstrate why this is the case.

Figure 18: Examples of energy dispatch for different regulation bidding strategies

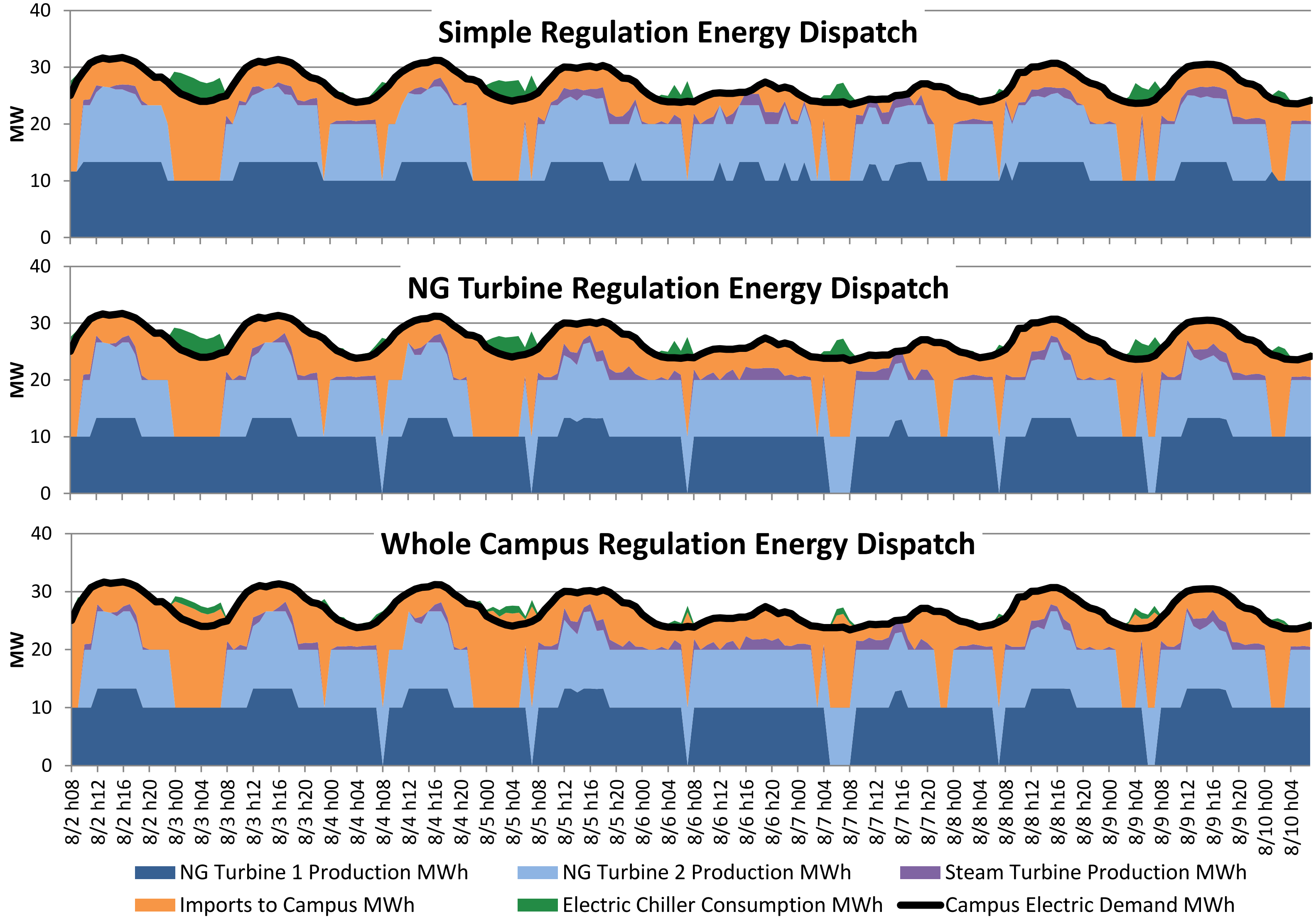
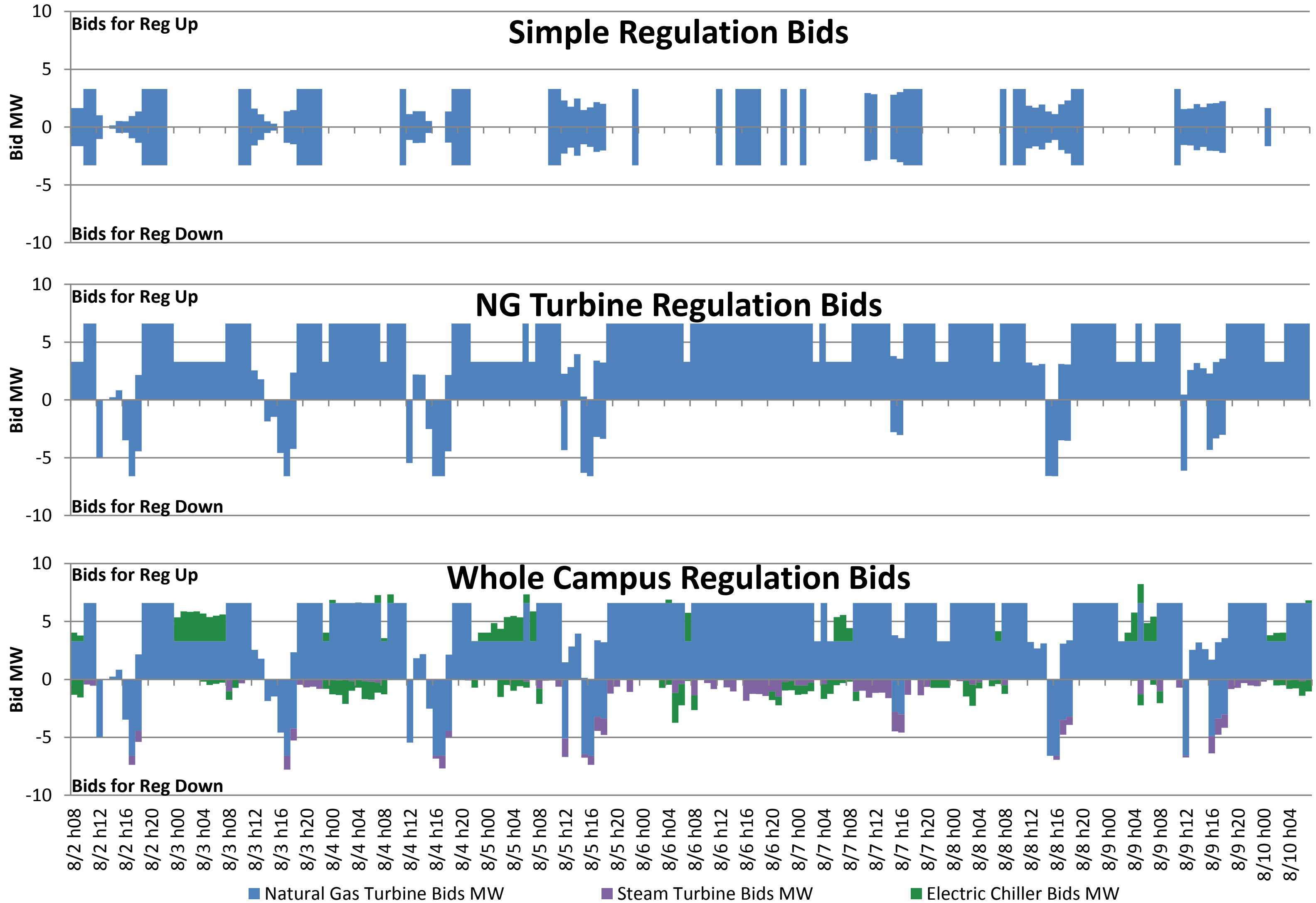


Figure 19: Regulation bids, up and down, for three different strategies for providing regulation.



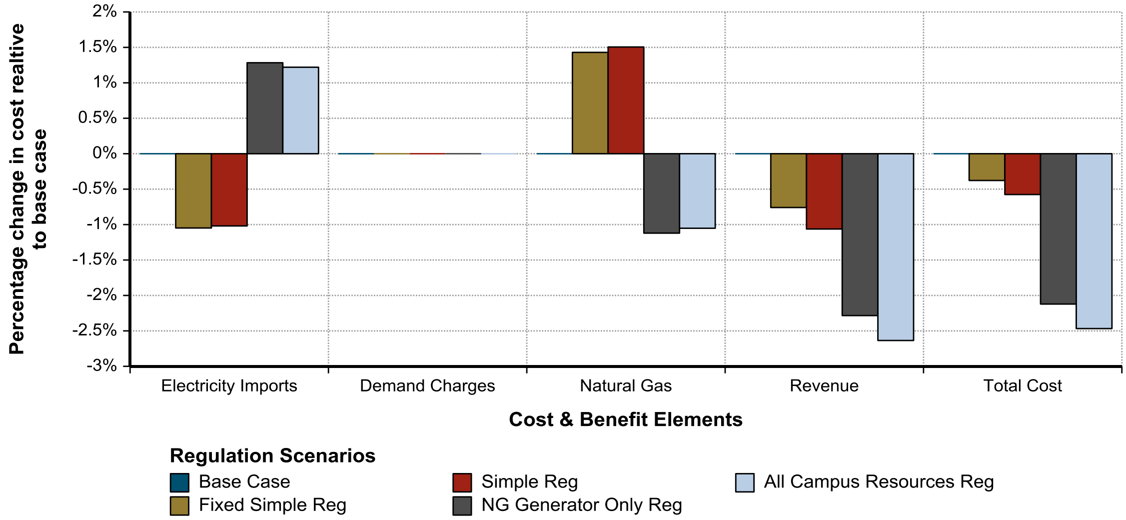
5.4.2 **Monthly cost impact**

We show the cost impact by resource in Figure 20. The main result shown is that there is a dramatic difference in costs and revenues between the two cases that require the same quanity to be bid in both directions and the two cases that allow different quantities in the up and down direction. Offering the same quantity in both directions reqires the generator to operate near the mid-point of 23.3 MWs to provide regulation. Under normal operation, the generators will operate predominately at 20 or 26. 6 MWs, or one generator will shut down entirely. The optimizer is generally choosing to offer regulation when the generators would otherwise operate at 20 MW. Therefore, the overall level of generation is increased, reducing imports and increasing natural gas consumption.

In the later two cases, such redispatch of the generators in not required. The optimizer tends to decrease generation (and increase imports) in preference to offer regulation up when it is lucrative. In these cases the reverse is true; imports are increased and natural gas consumption is reduced.

Our final insight is that with the steam generator and electric chillers, the costs (imports and natural gas consumption) are reduced relative to the generator only case, and the revenues are increased.

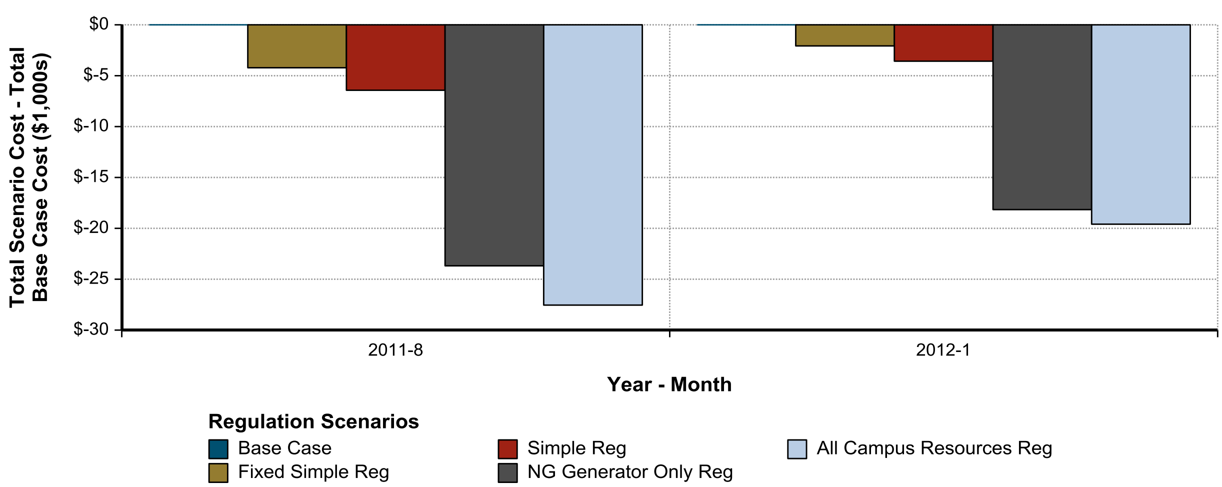
Figure 20: Percentage change in cost of regulation strategies relative to base case cost.



5.4.3 Monthly results

We show the net benefits in Figure 21. In the first two cases with the same quantity of up and down regulation bids, regulation revenues exceed the incremental costs by ~$5,000 in August and ~$3,000 in January. With additional flexibility, the net benefits increase substantially to ~$25,000 in August and ~$18,000 in January.

Figure 21: Change in monthly net costs for August and January.



At first glance this appears to be a positive result. It is true that adding flexibility, both in terms of the quantity that can be bid and in the resources providing regulation, increases the revenue that can be earned in the regulation market.

On the other hand, the net benefits from offering regulation pale in comparison to the overall campus energy costs. Total energy costs for the campus for August were just over $1.1 million. The net revenue from providing regulation is therefore roughly 2% of the total campus energy bill. In January, the situation is similar, net regulation revenues are approximately 2% of the total campus energy bill of $735,000.

This explains why the dispatch of campus resources stays relatively constant for the base case and all four regulation cases, the magnitude of potential regulation revenues is not sufficient to motivate substantial changes in the dispatch of campus resources.

5.5 Greenhouse gas emissions impacts

The purpose of renewables integration strategies is to enable greater penetration of GHG emissions, which results in GHG emissions reductions, not to directly reduce GHG emissions. Nevertheless, we report the GHG emissions impacts of the renewables integration strategies analyzed.

Figure 22: Greenhouse gas emissions impacts of renewables integration strategies

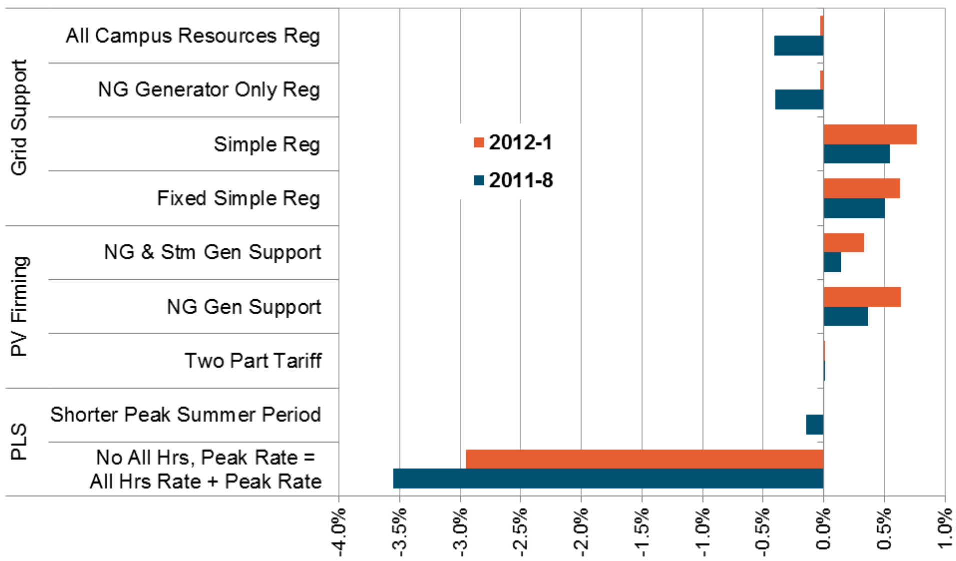


Figure 22 shows the GHG emissions impact of each strategy relative to its base case where a positive (negative) value indicates an increase (decrease) in emissions. Overall, the GHG emissions impacts are nominal. The PLS strategy in which the all-hours demand charge is removed has the most significant impact where GHG emissions are reduced by ~ 3%. By removing the all-hours demand charge, UCSD has more flexibility to turn off generators at night when thermal needs are lower. The other strategies result in impacts less than 1%. The PV firming strategies utilizing UCSD resources and the 'simple' and 'fixed simple reg' grid support strategies consistently result in small GHG emissions increases. In each of these four cases, generator capacity is reserved and must be able to provide both 'up' and 'down' services. The grid support strategies that allow independent up or down bids ('All campus resources' and 'NG generator only reg') result in a nominal GHG emissions decrease.

A consistent trend across all strategies is that as UCSD has more dispatch flexibility in the strategy, small GHG emissions decreases result. Still, these impacts are nominal and underscore that the renewables integration strategies may not necessarily reduce GHG emissions.

6 Conclusion

We draw several conclusions from the results of our work. They are presented here in four categories: Modeling, Operations, Tariff and incentives and Greenhouse gas emissions.

6.1 Modeling insights

Our modeling insights come from developing the UCSD Campus Dispatch Optimization Tool and working with UCSD operators to parameterize the cost benefit optimization model. Working closely with the UCSD energy manager proved instrumental in validating modeling results and identifying where focused detail is needed and where reasonable approximations can be made.

Integrating thermal resources in optimization is required for robust results: Good integration of thermal resources and their interactions with other resources in optimization proved crucial to winning operator confidence in the results. Integration studies tend to focus on electrical impacts, but heating and cooling are key additional primary end-uses. We find two threshold issues for campus operators: 1) Are the results credible and intuitive? and 2) Do they include downstream impacts in hot and cold water production?. Furthermore, both the physical and contractual relationship between a CHP system and its steam host can significantly constrain the flexibility of the generator.

Separate approaches are needed for monthly and daily period of analysis: As true for many large C&I customers, the monthly demand charge is a large cost driver for UCSD. Performing a full optimization over one month was not feasible in the optimization model to computational limitations. We find it most expedient to adopt the two stage approach presented in this study: a one month optimization, with approximations as needed for computational efficiency, to determine maximum demand for demand charges and TES dispatch; and a more detailed optimization over one to several days at a time to perform hourly or sub-hourly dispatch optimization.

6.2 Operational insights

Our modeling efforts and insights have produced results that offer some useful observations on UCSD resource operation. Our scenarios are modeled results and as such they do not fully capture the detailed considerations and uncertainties faced by UCSD microgrid operators. However modeling hourly dispatch for a full year has offered insights into how the strategies examined here could work with actual campus operations.

Integrated optimization and dispatch of campus resources can reduce costs while providing flexibility: Modeling optimal dispatch of campus resources proves effective in identifying strategies that can reduce costs or increase flexibility relative to standard operation. Currently, UCSD applies heuristics to dispatch resources, which are operated in a pseudo-steady state manner. Characterizing and optimizing campus resources demonstrates the capacity to perform additional services while meeting campus demands and achieve additional cost savings.

Incorporating additional resources in dispatch strategies does meaningfully reduce costs or increase flexibility: In both the PV firming strategies and grid support strategies, adding resources such as the steam generators or electric chillers to the available portfolio reduces the comparative campus costs and increases the quantity of service provided.

PV firming with campus resources appears feasible, but more expensive than current estimates of grid renewable integration costs: Using renewable integration cost estimates of \$8/MWh generated or \$31/MWh of forecast error – on the high end of renewable integration cost estimates – we find that using the campus resources to firm PV is not cost-effective. This follows the generally accepted wisdom that a diverse portfolio of resources over a wider geographic area will be more efficient in managing variability. Including additional campus resources (such as building loads or electric chillers) could reduce the campus costs. Furthermore, to the extent that there are higher local integration costs, DER's could still prove an economic resource for renewable integration.

Current prices for regulation are cost-effective for campus but revenues are small compared to total costs: Campus resources can provide frequency regulation in the CAISO market at today's prices cost-effectively. However, net revenues are only ~2% of the total campus energy cost. Regulation revenue can help justify investments in new resources, but will be supplemental rather than a main driver of the decision. Because regulation can be a demanding service with increased risk and O&M costs, additional incentives or alternative strategies (such as pooled provision of regulation by aggregated networks of distributed resources) will be necessary to encourage wider adoption.

6.3 Tariff and incentive insights

Our operational insights often arose together with insights about how changes in the cost UCSD faced or the addition of incentives could have substantial positive impacts on our integration strategies. Modeling shows the strategies in this work can be operationally possible and further work may show they are operationally feasible, but tariffs and incentives will be the final determinant of whether these integration strategies can be deployed.

Off-peak demand charge significantly constrains on-peak dispatch of campus resources: The SDG&E all-hours demand charge proves to be a significant constraint to the peak load shifting dispatch for UCSD. Because UCSD has significant load shifting capacity relative to peak net loads, load shifting frequently increases monthly peak demand, though it occurs in the off-peak period. Implementing alternative tariffs for recovering fixed costs could increase the peak load shifted by over 1 MW while still reflecting appropriate cost causation principles. While we did not model the all-hours demand charge with the other strategies, we expect that it will also prove to be a disincentive many strategies for using DER for renewable integration.

Two-part rates will be needed to encourage DER provision of renewable integration services: retail tariffs are relatively blunt instruments and impose significant risks and potential costs for customers seeking to provide renewable integration services. It is unrealistic to expect dynamic rates alone to provide sufficient incentives. In fact, as is seen in the PLS strategies, time differentiated rates can lead to counter-productive incentives when it comes to renewable integration. Supplemental tariffs and incentives that can be layered on top of retail rates without compromising utility fixed cost recovery will be necessary to engage the full potential of DER's for renewable integration.

Direct participation in wholesale markets do not provide sufficient incentives for campus provision of integration or ancillary services: Campuses like UCSD have a diverse and large portfolio of resources, but emissions, economic and end-use considerations limit the relative quantity of capacity available for providing grid support. We show these services can be cost effective from the grid perspective, but participation results in revenue that is a small percentage of total campus costs. Additional research or product development is needed to develop strategies to effectively engage to large C&I customer DERs in wholesale markets.

6.4 Greenhouse gas emissions insights

The bulk of this work focuses on strategy development, modeling and analysis of cost effectiveness, tariffs and business strategies. However we do provide rough estimates of the GHG emission impacts of the change in modeled dispatch for each strategy. These rough estimates yield the following key insight.

PV firming and grid support enable, but do not necessarily generate, emission reductions: The net GHG emissions impacts of each strategy, compared to its base case, are complex and varied across strategies. Emission impacts are driven by the tradeoffs amongst campus generators, the level of campus steam-utilization/overall system efficiency and the carbon content of imported electricity. Overall, we observe that those strategies that provide more flexibility to the generator operation tend to result in small GHG emissions decreases. As the UCSD system provides PV firming services using its own resources, overall GHG emissions are increased nominally (~ 0.5%). The impact for grid support is more complex. As the grid support product is more flexible, allowing the campus to provide either up or down movement, GHG emissions decrease; when the generators are required to provide equal up or down movement, GHG emissions increases, similar to the PV firming case based on UCSD resources.

Our GHG emissions impacts are rough estimates and limited in scope. A more detailed treatment of resource efficiencies at varying output levels could improve our understanding of how tradeoffs between relying on campus resources vs. the grid influence GHG emissions impacts. Additional granularity on electric grid emission intensities, including a break out of emission rates for the typical generator that would be providing PV firming or regulation in the absence of UCSD's participation, would be informative. Our analysis also focused on strategies that heavily leverage the UCSD generation resources. If integration services are based on load reduction, such as that offered through event-based demand response, GHG emissions impacts are likely to be lower.

Our preliminary findings are, however, consistent with intuition and similar studies that suggest renewables integration services are 'enabling' strategies rather than GHG emissions reductions strategies on their own.

7 Findings & Recommendations

Combining the results of this analysis together with the broader insights formed during the process we have formulated these combined findings and recommendations to policy makers.

7.1 Findings

Value and cost estimates for local, distribution grid support and integration services are needed, but not readily available. There is little, if any, public cost estimates for local and distribution level impacts, which are frequently the primary limiting concerns for utility operators when it comes to high PV penetration and EV charging. These services are potentially more valuable and lucrative than wholesale grid markets. Identifying, developing and quantifying high cost/value services for local grid support is crucial to properly reflect these costs both in customer rates, and in incentives for increased customer, vendor and service provider engagement.

A public and transparent framework to explicitly compare central, distributed, load and market based renewable integration and GHG reduction strategies is needed. Although several initiatives and proceedings are examining long-term planning and procurement for flexible resources and renewable integration, there remains no framework to readily evaluate and compare the diverse portfolio of alternative strategies available to utilities and policy makers. A guiding framework for evaluating the relative costs and benefits of resources like CTs, energy storage, demand response and the CAISO Flexi-ramp product in meeting identified system needs would be instrumental in identifying and developing high value, low cost strategies in each category.

The limited value of net AS market revenues relative to total energy costs reinforces the importance of non-price strategies to engage the substantial resources of large C&I customers for integration and ancillary services. In eastern ISO markets, DER's now provide up to 10% of the total MW's enrolled in centralized capacity markets. Participation in reserve and AS markets is much more limited. Our analysis suggests that access to wholesale markets alone is insufficient to motivate participation by UCSD and by proxy, other large C&I customers. Our findings together with the experience in eastern ISO markets suggests that, customer engagement and outreach will be important elements in encouraging DER to provide renewable integration.

Implementing optimization tools at UCSD proved even more challenging than anticipated on a number of levels. The operation of sophisticated, multi-resource combined energy and thermal systems like the UCSD Microgrid is extremely complex. An experienced team approached this project with no illusions about the modeling, optimization and system integration challenges entailed. Even so, acquiring, processing and cleaning data from multiple sources proved time consuming, even for a well metered campus. The historian and telemetry need for real-time and near real-time campus data was still being configured during the course of the project. We determined that evaluating scenarios would require separate, computationally efficient optimization approaches hourly dispatch over daily and monthly/annual periods. Accounting for uncertainty or increased operational costs or risks from complex operational strategies will be important to include in future modeling efforts.

7.2 Recommendations

Restructure all-hours demand charge for PLS customers: The current all-hours demand is intended to fixed distribution costs driven by all-hours customer loads. However, the charge paradoxically reduces the incentive for UCSD to engage in PLS, which is generally presumed to reduce both system and distribution capacity costs. It discourages PLS at a time when system operators are claiming an increased need shifting peak loads to absorb excess off-peak generation and to replace local capacity lost due to the San Onofre Nuclear Generating Station outage. Restructuring the all-hours demand charge for UCSD and other customers with significant load shifting capacity could meet both objectives at little or no cost to utilities or ratepayers while still accurately reflecting cost causation.

Allow utilities to negotiate terms specific to individual, large C&I customers: UCSD is an example of a large, underutilized resource for SDG&E. The all-hours demand charge is counter-productively limiting peak load shifting, and established baseline rules base on 10 historical days are too inaccurate and risky for UCSD to enroll in established DR programs. There is established precedent for utilities to negotiate special rates for customers considering bypass. A similar policy of allowing utilities to negotiate customized terms to facilitate the maximum participation by local distributed resources should be considered.

Support an implementation study of DER integration strategies using UCSD as a pilot site: To enable the large existing pool of DER to engage in strategies to enable greater renewable integration the work that has been done for UCSD will need to adapted to range of applications and disseminated. While this work models the dispatch of UCSD resources under proposed renewable integration strategies a vital next step in realizing these strategies is piloting their actually operation at the campus. The modeling conducted in this analysis does not address the uncertainty and nuances facing by system operators. An effort to operationalize these strategies for UCSD would leverage this work and produce a great deal of information on how modeled strategies translate to real world operation.

8 Public benefits to California

The results of this project are relevant beyond UCSD that could promote DER adoption and the use of DER for renewables integration. Although the project did not meet the original goal of demonstrating specific strategies at UCSD in a live environment, the results provide useful insights for customers and policy makers that can provide economic and environmental benefits in the near-term.

+ **Technical potential**. C&I customers have significant technical potential to provide renewables integration strategies in California. College campuses total 500 MW of load; industrial customers total over 2000 MW of load[8] and have many flexible end-use loads (pumps, fans, motors); there are ~ 8500 MW of combined and heat and power systems at ~ 1,200 sites in California[9].
+ **Simple policy changes.** Our analysis shows that a simple policy change —restructuring the all-hours demand charge can decrease load by ~ 1 MW at UCSD. The value of reducing load by 10 MW (2% of California campus load) is ~$1.0 Million/year using 2013 avoided capacity costs. (Capacity value in Local Capacity Requirement (LCR) area such as San Diego are not publicly available but generally estimated to be much higher.)
+ **Integration at the distribution level.** Our analysis suggests UCSD can firm its solar PV using its own resources at a cost comparable to relying on the grid, even using relatively high estimates of renewables integration costs. However, local integration costs are uncertain and could be higher than average integration costs, which increases the value of using DER to provide firming. The two-part that we describe when firming with the grid can be implemented with smart meters.

[8] Itron 2007, Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond Task A4 . 1 Final Report : Scenario Analysis to Support Updates to the CPUC Savings Goals Main (2007), at 37.

[9] ICF International, 2012. Combined heat and power: Policy analysis and 2011-2013 market assessment. Report prepared for the California Energy Commission. Report CEC-200-2012-002

- **Insights on grid support.** Our analysis of grid support suggests it is economical for UCSD to provide grid support based on regulation prices but the net benefit to UCSD is relatively low. Ancillary service revenue alone may be insufficient for motivating loads to provide grid support and alternate products and incentives may be required.

Beyond renewables integration, this project provides insights, tools and strategies that can be used by California colleges to support efforts in reducing energy consumption, costs and GHG emissions. For example, achieving the GHG emissions reductions called for in the University of California's Policy on Sustainable Energy Practices (which encourages carbon neutrality as soon as possible) presents numerous challenges and will require new analysis tools and innovative strategies such as those described in this study.

9 References

9.1 Companion Reports

Available at: calsolarresearch.org/Funded-Projects/second-solicitation-funded-projects.html

Task 2: Strategies for Integrating High Penetration Renewables Report

Task 3: Tariffs and Incentives for Integrating High Penetration Renewables Report

Task 4.1: Deliverable (Final)-VPOWER Installation Report

Task 4.2: Expansion of DER Model CSI 2 Grant

Task 4.3: VPower Enhancements Report CSI 2 Grant

Task 5: Report on baseline performance for UCSD DER operation under current rates and incentives

9.2 References

CAISO (2012) Flexible Ramping Products: Second Revised Draft Final Proposal http://www.caiso.com/Documents/SecondRevisedDraftFinalProposal-FlexibleRampingProduct.pdf

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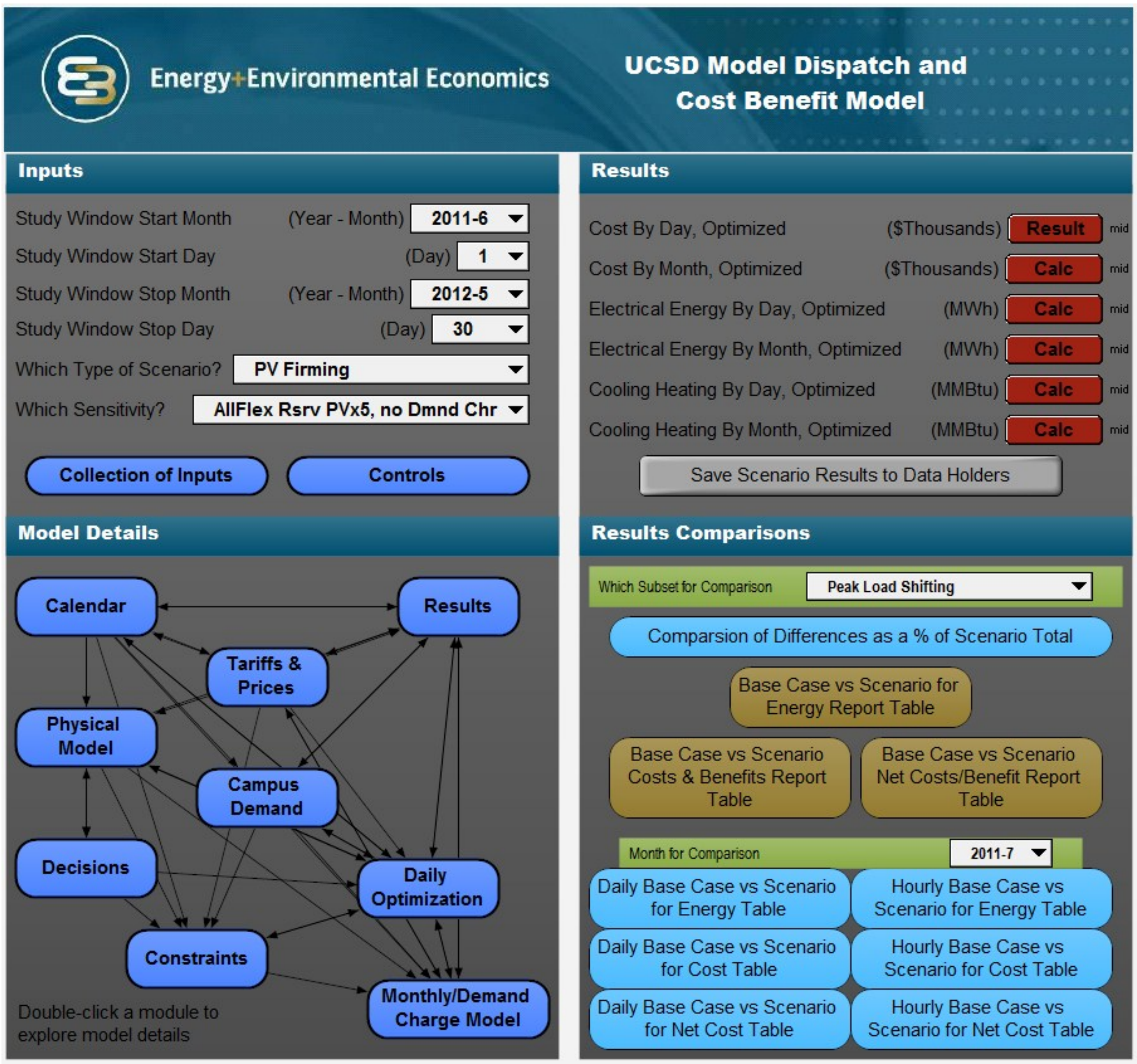
Energy and Environmental Economics (2011), California Solar Initiative Cost-Effectiveness Evaluation. http://www.ethree.com/documents/CSI/CSI Report_Complete_E3_Final.pdfItron (2007). Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond Task A4.1 Final Report : Scenario Analysis to Support Updates to the CPUC Savings Goals.

Keith Casey, Keith Casey Memorandum to ISO Board of Governors: Briefing on Renewable Integration (2011), http://www.caiso.com/Documents/110825BriefingonRenewableIntegration-Memo.pdf

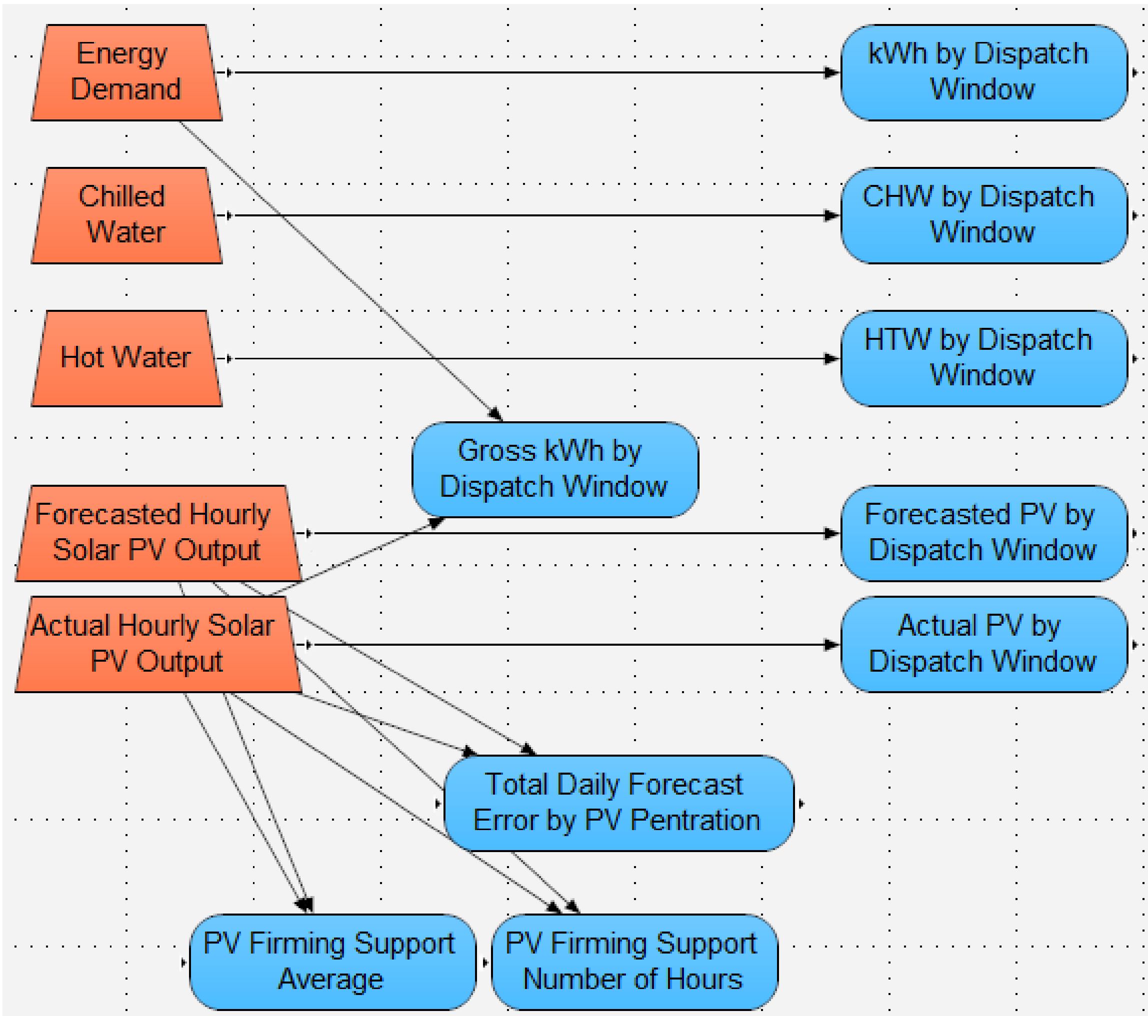
PG&E, SCE, SDG&E. Joint IOU Supporting Testimony. July 1 2011, CPUC Long Term Procurement Proceeding, R. 10-05-006. http://www.cpuc.ca.gov/NR/rdonlyres/070BF372-82B0-4E2B-90B6-0B7BF85D20E6/0/JointIOULTPP_TrackI_JointIOUTestimony.pdf

Appendix A – UCSD Campus Optimization Tool – Selected Screenshots

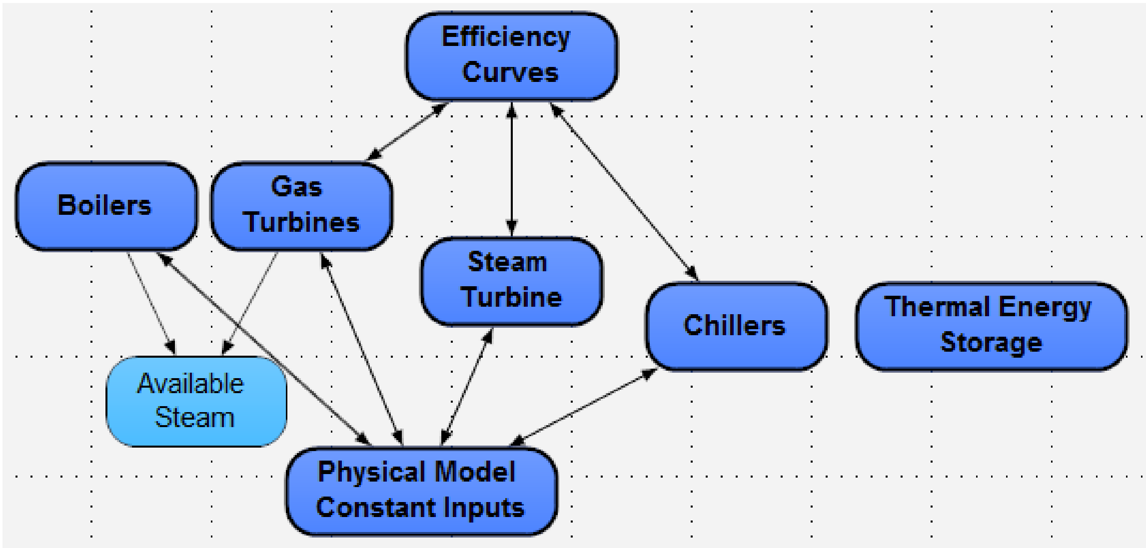
Model overview



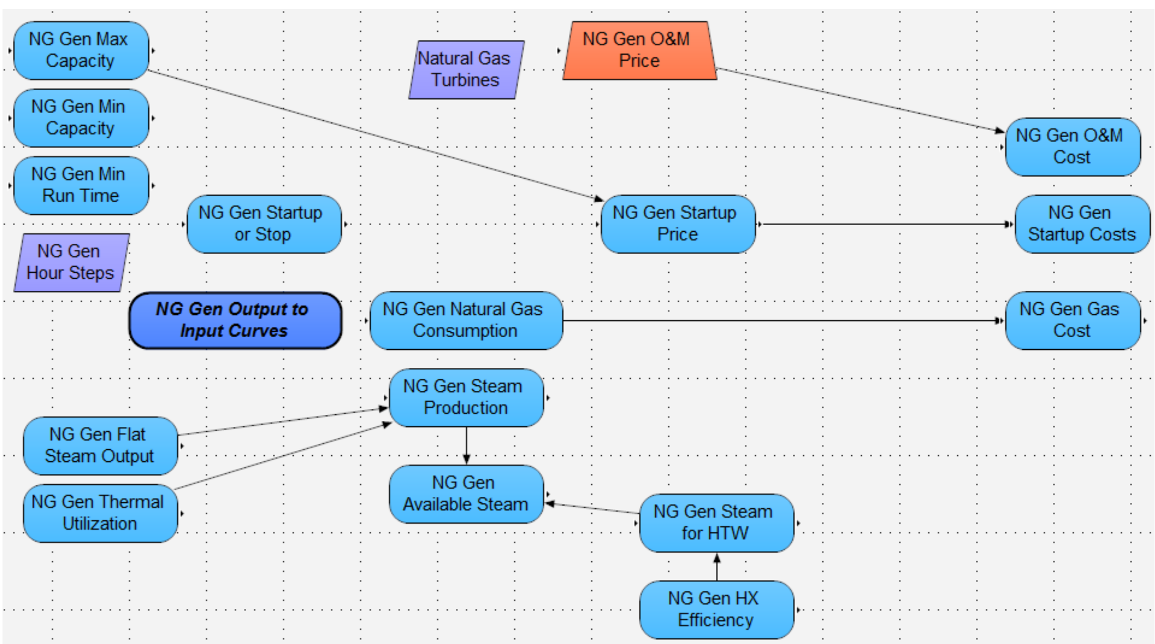
Campus demand



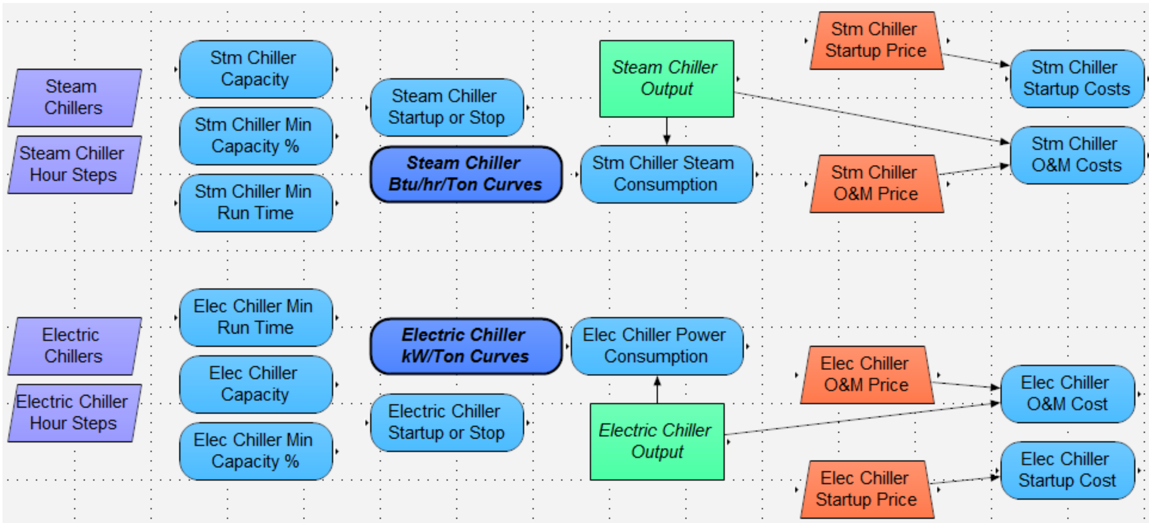
Physical Model



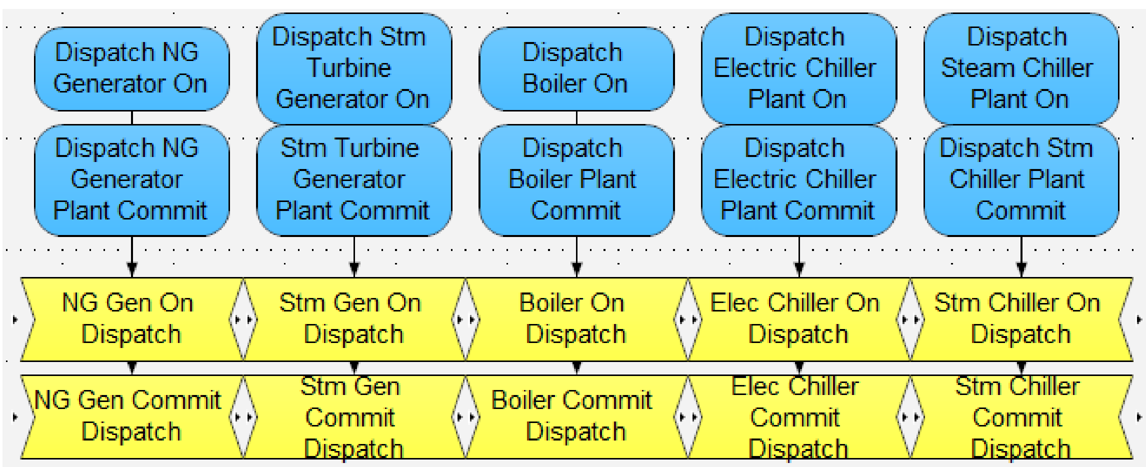
Gas turbines



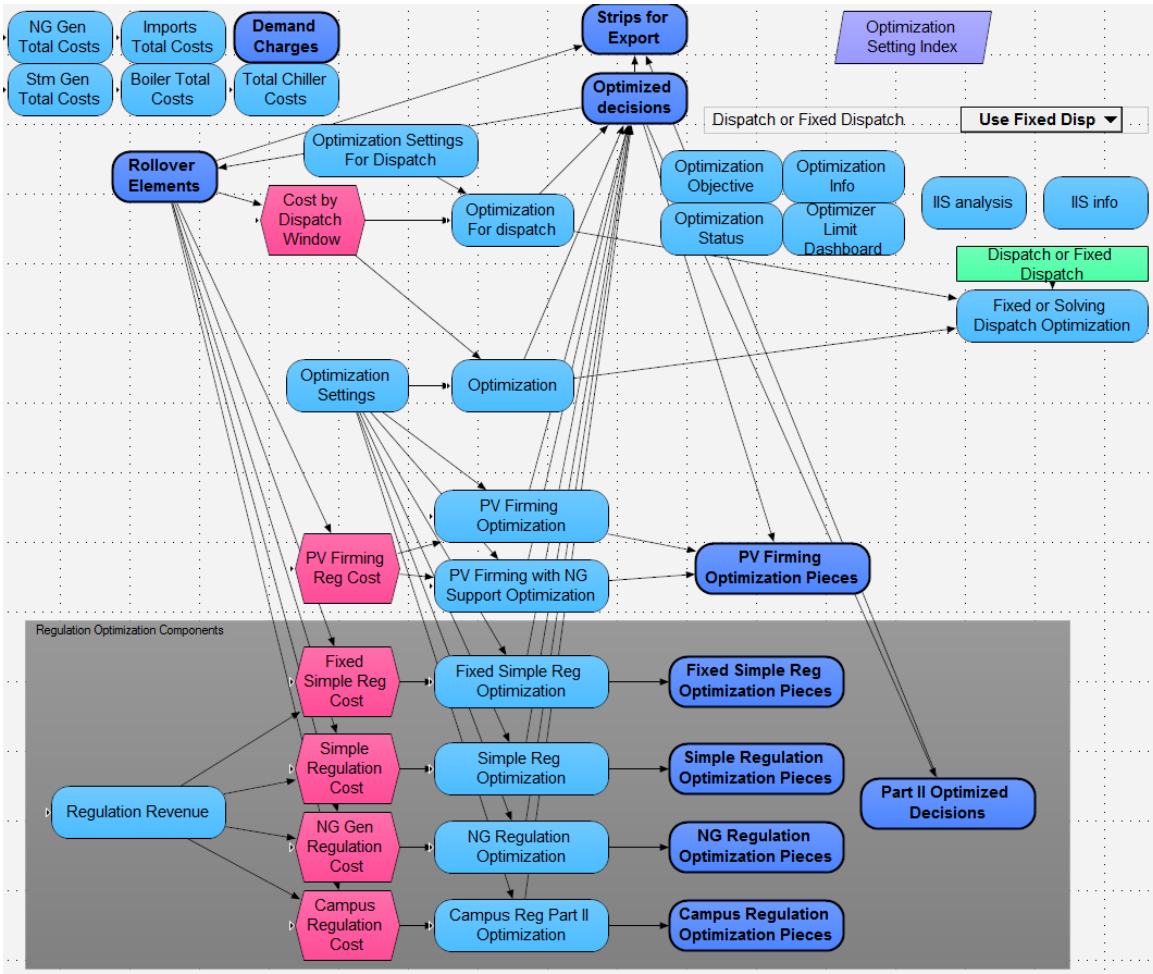
Steam and electric chillers



Constraints

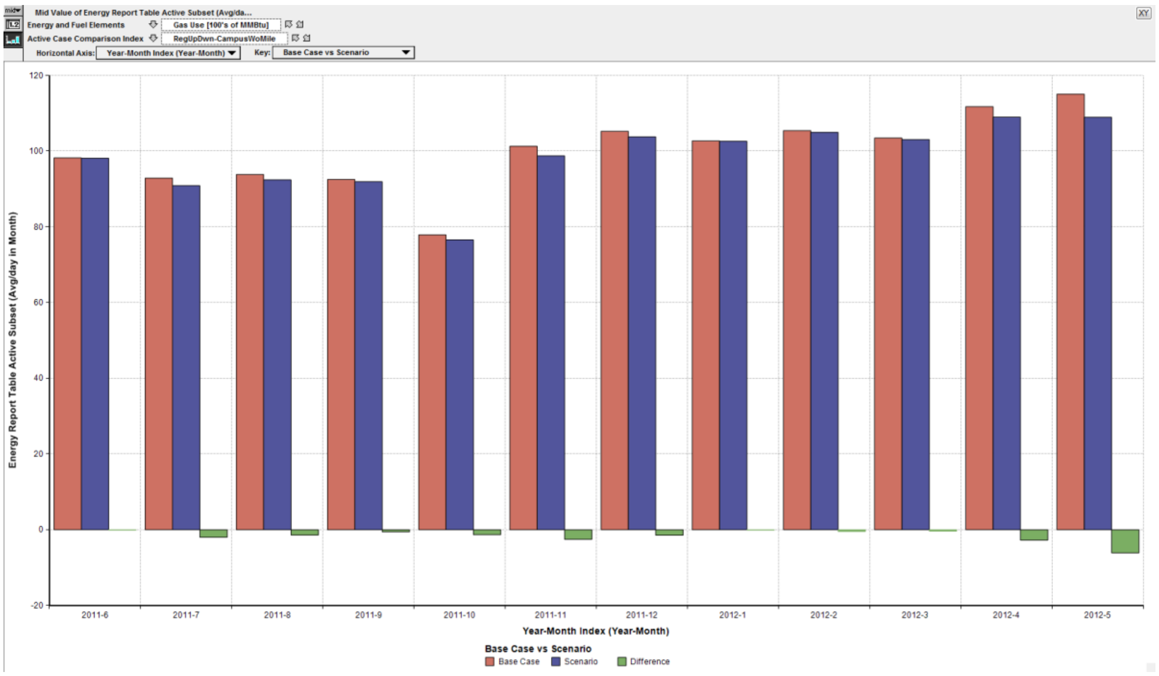


Optimization

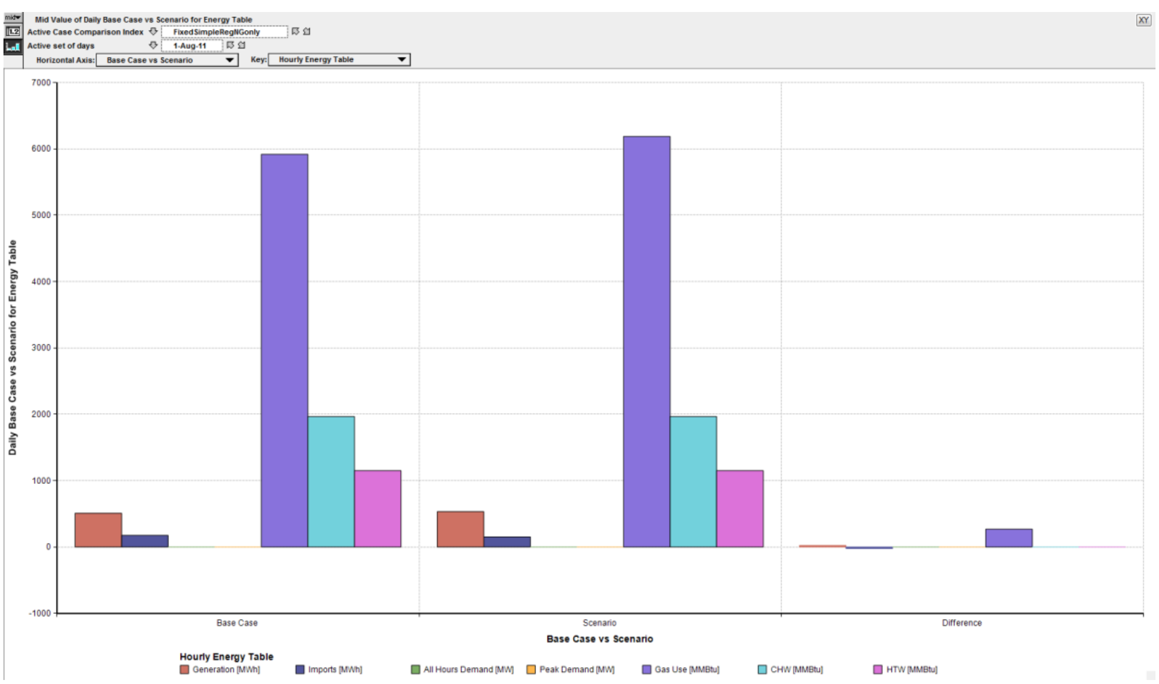


Results

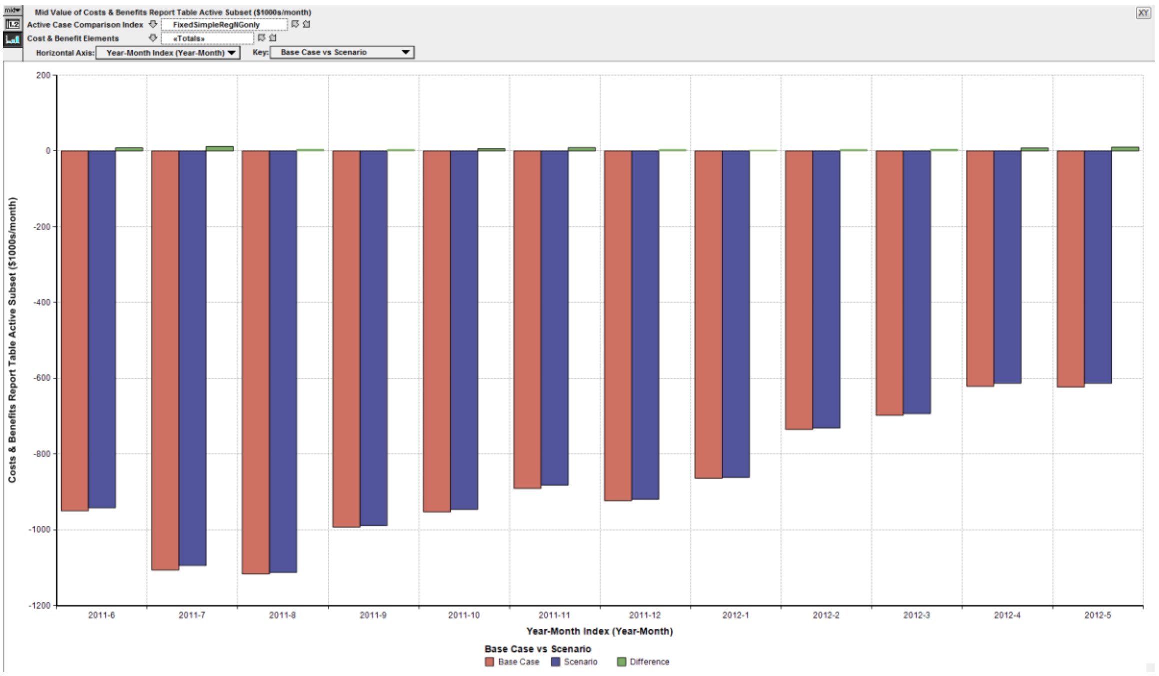
Energy exports: base case vs. scenario case for full year



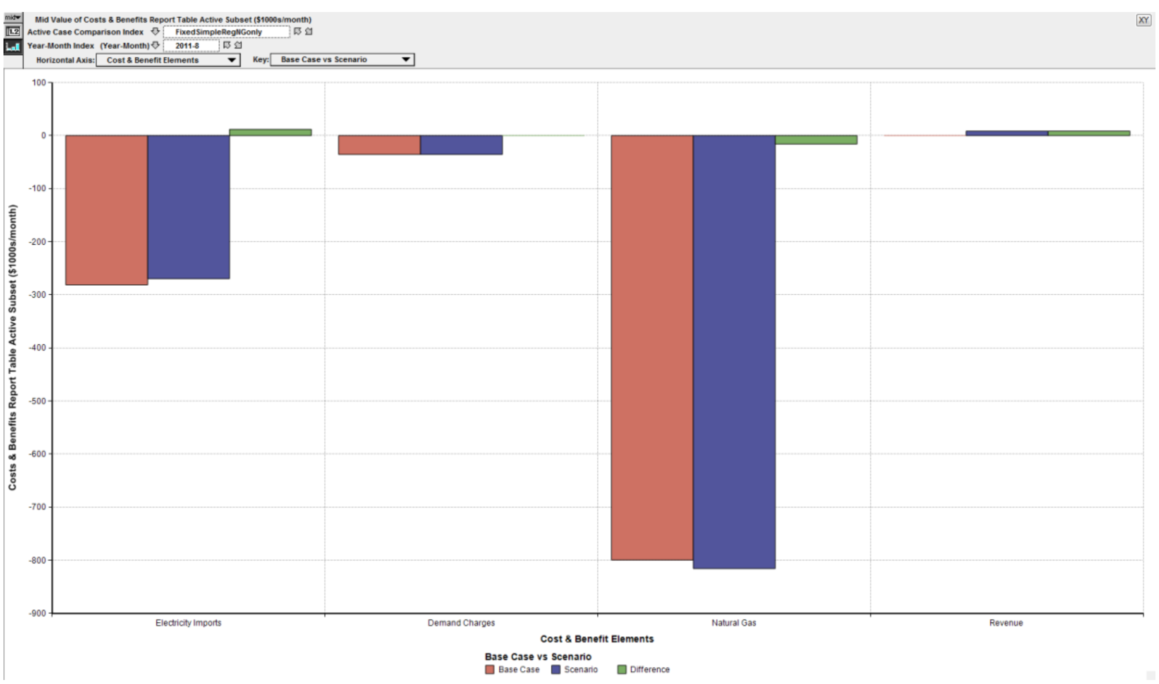
Energy use: base case vs. scenario case



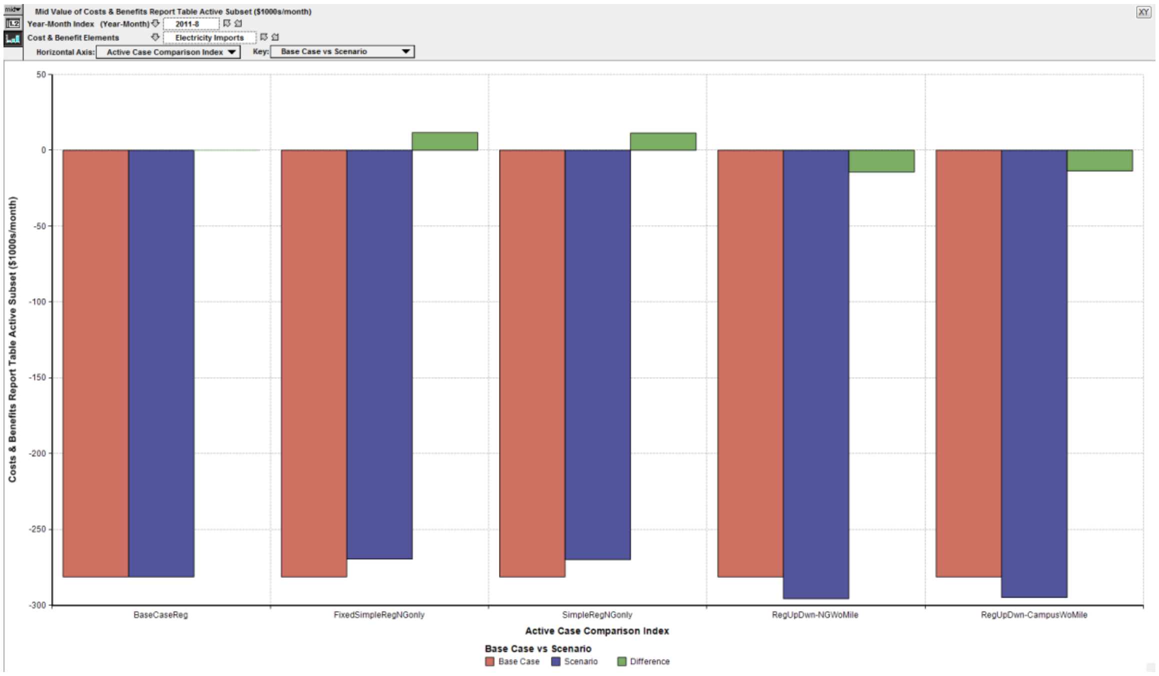
Net Cost: base case vs. scenario case for full year



Net Cost: base case vs. scenario case, by category for one month



Electricity Imports: base case vs. scenario case across all scenarios for one month



Average daily output, by resource for one year